Orbit

Volume 25 • Number 2 • 2005

Where does it hurt?

Using Diagnostics and Optimization to Alleviate the Pain

- Closing the Loop at Whiting Clean Energy
- Online Condition Monitoring at Wisaforest
- System 1® Success at Turów
- The All-New ADRE® System
- When Peak Readings Don't Agree
- Oil Analysis 101

Orbit

A Technical Publication for Advancing the Practice of Operating Asset Condition Monitoring, Diagnostics, and Performance Optimization

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EDITOR'S NOTE

At 44, most people wouldn't consider me old (unless you happen to be my nine-year-old son...then I'm like WAY old), but the inevitable aging process is still showing in a number of ways. Like the number of gray hairs. And trips to the doctor. They used to be twice a year on average – once for the occasional cold or flu, and once for a yearly check-up. These days, they seem to be a lot more frequent. Don't get me wrong, I'm not gravely ill or anything, but I'm realizing that a fairly sedentary lifestyle, the pace of life in the 21st century, and eating pretty much whatever I wanted to my whole life – it's all catching up to me. Not so much in weight (I've always been on the slender side), but more in terms of my general feeling of wellness. So, I've been eating healthier, exercising regularly, and learning to manage stress better. And you know what? It's making a difference. I'm staring to feel like my old self again.

What's that got to do with this issue of ORBIT? Quite a bit, actually.

I've learned that I can't assume this body will run perfectly indefinitely. I have to be aware of how I'm stressing it, the fuel I'm putting into it, and how to optimize its performance through exercise and nutrition while balancing that with the other priorities in my life. Pretty basic stuff. Not unlike the challenges you face in your plants – balancing production demands against assets that wear out, have problems, face unexpected stresses, and consume fuel. You can't take your assets for granted. You have to manage them, or they'll start to manage you.

In this issue of ORBIT we provide case histories on pages 34 and 56 from widely different industries, showing how they have gained control of their assets through proactive operating and maintenance strategies along with our condition monitoring and optimization technologies. It's made a difference in not just the health of their assets, but the health of their businesses as well. And all without having to eat more broccoli.

In this issue's pages we also introduce our readers to the latest generation of the ADRE® System, our premier multi-channel portable system for machinery analysis and diagnostics. First introduced in 1980, it's come a long way in 25 years. You can read more beginning on page 60. Also in this issue, we introduce our readers to another powerful optimization tool: the CLOC™ system from GE Energy, which takes thermodynamic performance monitoring to a whole new level of effectiveness by "closing the loop." A product overview and case history appear on page 4, providing an excellent example of how this technology can be successfully applied. Finally, if you've ever connected a portable data collector to your Bently Nevada® rack and found a discrepancy in the readings between the two devices, you'll find the 2-part article on page 18 particularly relevant. It helps take the mystery out of why instruments may not often agree with one another, and why it doesn't always signify a problem with either device (part 2 will appear in our next issue).

As always, we hope you continue to find ORBIT educational and practical, with the right mix of applications, case histories, and product information. I'd love to hear from you regarding whether we are "hitting the mark" in this respect. If you haven't yet participated in our online reader survey, please take a moment to give us your thoughts at www.gepower.com/orbitsurvey. It only takes 5-10 minutes and really does provide us with the most valuable feedback of all – yours.

—Steve Sabin

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- Case History: Diagnosing A Generator Short
- Runout 101: How to spot it, how to correct it
- Sonic Horn Monitoring For SCR Applications
- Optimized Coal Blending

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CASE HISTORY
PAYBACK PROFILE

Closing the Performance Loop

How Whiting Clean Energy uses GE's CLOC™ System For Optimal Generation and Efficiency

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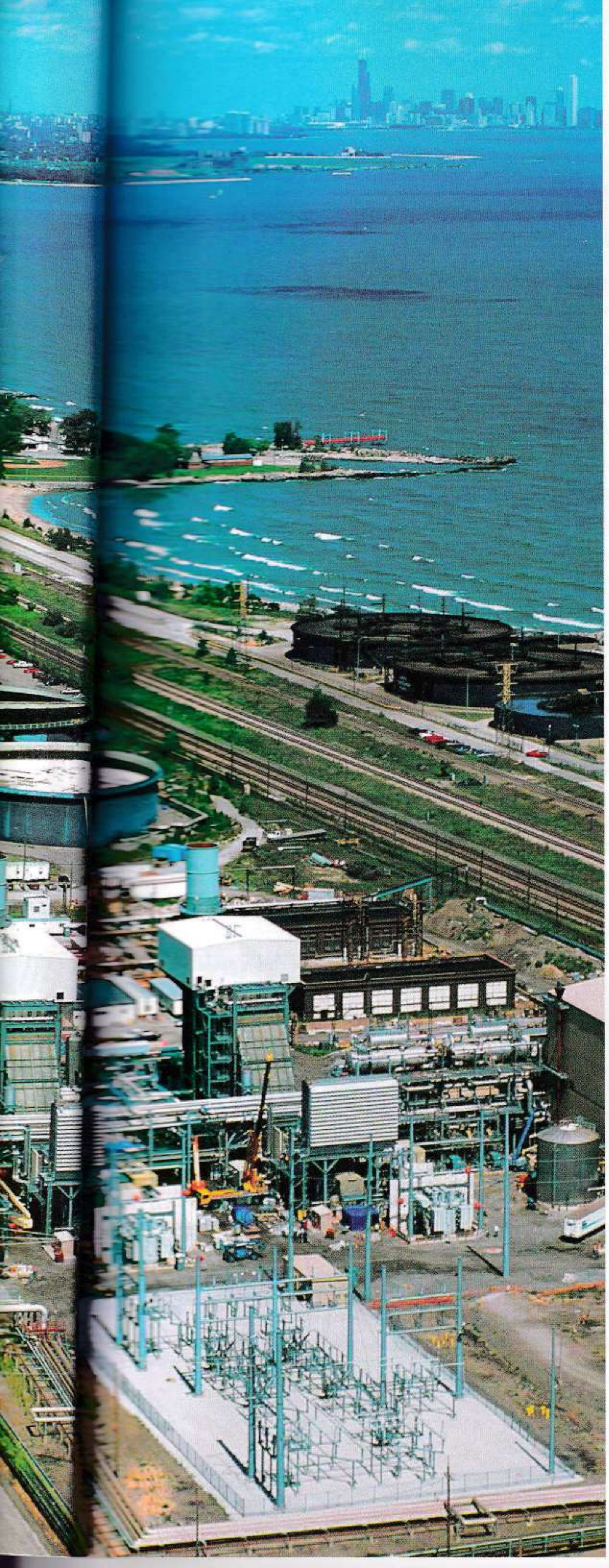
[Editor's Note: In the previous issue of ORBIT (Volume 25, No. 1, 2005), our article on performance monitoring for gas turbines (pp. 64-74) presented a tutorial on thermodynamic performance monitoring and briefly introduced readers to EfficiencyMap™ software and its online optimizer module. Here, using actual results achieved by Whiting Clean Energy, we show how these products can effectively be used as part of a closed-loop optimization and supervisory control system to improve overall plant efficiency along with optimal generation within constraints.**]**

Introduction

GE Energy's Closed Loop Optimal Control (CLOC™) system was installed in 2003 at the Whiting Clean Energy (WCE) cogeneration facility in Whiting, Indiana. The objectives of the project were threefold:

1. **To continuously optimize** electric power generation and steam production by closely matching the dispatched generation and minimizing over-generation;
2. **to protect against** constraint violations, such as NO_X emissions above the allowable limit and minimal steam flow to the steam turbine;
3. **to improve** plant heat rate and efficiency.

This article describes how the CLOC system works, how it was applied at WCE, and the results obtained.



THE CLOC SYSTEM
REDUCED VOLUNTARY OVER-GENERATION
BY 90% (OR 3.7 MWH/H ON AVERAGE)

Closing the Performance Loop

GE's CLOC system, which utilizes real-time performance monitoring and optimization, is commonly used to optimize the operation of simple- and combined-cycle plants for maximum profitability. The system determines the most profitable way to operate such plants given "time of day" or "dynamic" fuel variations, electricity and steam prices, load levels, equipment degradation, and operational constraints. In fact, the more dynamic the plant operation, and the more complex the process, the greater the opportunities for CLOC optimization and associated customer profit or margin enhancement.

As applied at WCE, the CLOC system ensures that certain controllable operational limitations, such as NO_x levels and minimum steam turbine steam feed, are not violated. It also matches the net generation dispatch closely, thereby minimizing voluntary over-generation. In addition, the plant is operated at an improved heat rate by employing an online thermo-economic optimizer. Exact control of generation is important at this site since the plant runs most economically when there is neither over-generation nor under-generation.

As will be shown, the CLOC system reduced voluntary over-generation by 90% (or 3.7 MWh/h on average) without causing any under-generation. Also, the ability to protect against certain operational constraint violations proved to be very effective using the CLOC System.

Whiting Clean Energy cogeneration facility in Whiting, Indiana, U.S.A.

Why Close The Loop?

Continuously maximizing plant efficiency is difficult today because power generation by merchant power producers (both simple- and combined-cycle) and cogeneration facilities involves operating challenges from fluctuations in prices and costs. Host steam demand is continually changing, requiring continuous action to ensure that scheduled (contracted) sales to the electric grid and the steam host are met. These challenges are further complicated by environmental and operational constraints, along with other limitations imposed on the plant. The resulting complexities can make it very difficult for a plant to reach its goal through manual control alone.

The installation of an online optimizer, such as the one included in GE's EfficiencyMap™ software, can help by calculating optimum steady-state setpoints for maximum efficiency of both steam and power production. However, while an online optimizer may provide optimal setpoint information, *it does not close the loop* – it instead relies upon manual implementation of recommended setpoints.

Another consideration when optimizing is the dynamic nature of plants. For example, a cogeneration facility has no direct control over host steam demand, nor captive power use by a power host. Such demand variations and process dynamics in both electrical and steam systems translate to optimal dynamic operating points that differ from optimal steady-state operating points. An effective optimizer must be capable of addressing these dynamic fluctuations.

Prior to the installation of the CLOC system, WCE operators manually adjusted their control systems in order to follow changes in both steam and power demands. It was recognized that manual intervention to continually adjust setpoints was impractical if the plant was to realize its full optimization potential. Thus, a fully closed-loop optimization strategy was pursued to ensure that (within mechanical system limits):

- Generating targets could be met dynamically (block tie-line control) at the point of sale (not at the generators), resulting in a significant reduction in voluntary over generation.
- Steam production could match demand continuously, thereby improving the steam availability while protecting the steam turbine against low steam flow.
- Some operational constraints could be actively controlled, thus reducing the number of reportable non-breach incidents.
- Interaction requirements for operators could be reduced. Implementation of setpoint adjustments could be automatic, resulting in continued operation at optimum settings for maximum efficiency.
- Dependence on operators to monitor and adjust CLOC-controlled units while starting additional assets could be eliminated. The CLOC system could account for the net output of all generators, whether under system control or not, thus ensuring that dispatched generation could be met accurately.

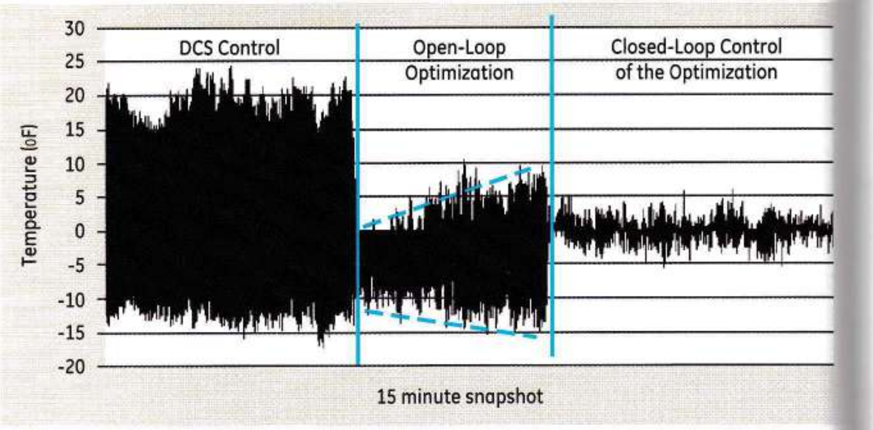


Figure 1 – **Temperature variation in a fired reformer showing dramatic effects of closed-loop optimization (right) when compared with open-loop optimization (center) and no optimization (left). Note how open-loop optimization drifts over time due to operator distractions.**

About Whiting Clean Energy

Whiting Clean Energy is a 525-MW combined-cycle cogeneration plant with two gas-fired combustion turbine units, duct-fired heat recovery steam generators (HRSGs), and a condensing steam turbine with a closed cooling water system. The facility sells high-pressure steam to its host, BP's Whiting Refinery. All of the power is sold on the grid.

The combustion turbines are GE Model PG7241FA (MS7001FA), which are fired on pipeline-quality natural gas. The fuel conditioning system consists of compressors, particulate filters, pre-heaters, and coalescing filtration for the heavy hydrocarbon removal from the natural gas prior to combusting the fuel in the turbines. The fuel compressors are three 50% capacity units. A Dry Low NO_x combustion system is supplied on each turbine for emissions control. Each turbine is rated at 166.6 MW (ISO conditions).

The HRSGs connected to each combustion turbine utilize the hot exhaust gases to generate high-pressure and low-pressure steam and to preheat the feed water. The high-pressure steam conditions are 1300 psi and 860° F. The low-pressure steam is utilized for pegging steam for the external deaerators. Natural gas-fired duct burners provide each HRSG with the ability to double the steam production. The duct burners consist of a burner management system with flame scanners and fuel control valves. A Selective Catalyst Reduction (SCR) System is provided with each HRSG and consists of an anhydrous ammonia system with a storage tank, vaporizers, and associated injection equipment. Each HRSG has its own stack with a continuous emissions monitoring system.

The steam turbine is a GE down-flow condensing unit with a closed cooling water system. The turbine auxiliary equipment consists of a lube oil system, hydraulic system, steam seal system, and a Mark V control system. There is also a steam-turbine-bypass letdown valve, which dumps the steam directly to the surface condenser. The generator is hydrogen cooled with a rating of 213 MW.

COMPARISON OF CONTROL MODES

- **DCS Control (No Optimization)**

  In DCS control, the operator implements setpoints manually, based on historical settings or a series of adjustments to bring the plant to the best-known operating condition, without assistance of optimization models or tools. Large variations in performance are possible, due to changing dynamics from demand or steam generation, and the difficulty in making such adjustments continuously and optimally.

- **Advisory (Open-Loop) Optimization**

  In advisory mode, a supervisory system (such as GE's EfficiencyMap software and its online optimizer module) generate recommended optimal setpoints every 3-5 minutes. However, operators are expected to implement these setpoints manually. While an operator can initially move the plant towards an improved operating point, the vigilance required to continually make such manual setpoint changes will generally deteriorate with time, and the plant will slowly "drift" from its optimal operating point. There are numerous tasks incumbent upon most operators – not just setpoint adjustments – along with numerous distractions. This helps explain the deterioration of advisory-only optimization over time and the desirability of closed-loop optimization.

- **Closed-Loop Optimization**

  By automatically implementing the recommended optimal setpoints supplied by the optimizer module, not only can a plant operate closer to its optimal operating point, but this advantage can be maintained over time. Variation in control of the process is dramatically reduced. The process is now stable and more efficient with greatly reduced operator interaction.

Figure 1 illustrates the variance in these three control modes for a fired reformer. The optimization algorithm required 2400 setpoint changes per hour, underscoring why open-loop optimization is neither practical nor sustainable for many optimization applications.

THE OPTIMIZER MUST THEN MEET POWER AND STEAM DEMANDS WHILE MINIMIZING OVERALL HEAT RATE OF THE FACILITY.

How CLOC Works

In order to reach the stated objective of lowered generating costs through both reduced fuel consumption and minimized average over-generation, automatic supervisory-level control is applied to the critical generating assets. The CLOC system actively sends generating setpoints to the governor for each turbine generator, as well as firing-rate setpoints to the burner management system of the duct burners.

The process itself is straightforward: at any point in time, the advanced supervisory control knows how much power generation is required to cover dispatch and parasitic load demand and how much extra steam is required to cover host steam demand. These values are fed to the online optimizer with instructions to distribute the power over the available assets and to calculate the firing rates of the duct burners. The optimizer must then meet power and steam demands while minimizing overall heat rate of the facility.

After calculating an online heat and mass balance and reconciling the data (the heat and mass balance errors will be minimized and incorrect measurements recalculated), plant and component efficiencies can be calculated, and thus performance degradation. The CLOC system uses models from GateCycle™ heat balance software, which is widely used in the power industry for design and off-design studies of power plants.

The system analyzes performance at the equipment level (gas turbine, HRSG, steam turbine, condenser) compared to design conditions as quoted by the OEM data as well as data created by models of the entire plant. Based on this analysis, the performance of the equipment is known along with its incremental cost. This data suffices to optimize the generation and steam production at the lowest cost (heat rate), taking operation and environmental constraints into account. The optimal solution found will be a valid operating point for the facility.

The optimal generating targets and firing rates are transmitted to the controller module of the CLOC system. The supervisory controller is charged with bringing the plant towards this optimal operating point on a trajectory that continues to generate steam and power as dispatched, while preventing violation of physical, environmental, and regulatory constraints. However, due to time lag, the previous steady-state optimal operating point may no longer reflect the current dynamic optimal operating point. The steam demand (something the plant has no control over) can change rapidly, directly impacting the output of the steam turbine generator. As such, the controller will bring the plant close to the optimal, steady-state operating point, while ensuring that constraints are not violated and that dispatch (steam and power) requirements are addressed most favorably.

To maintain maximum profitability at Whiting Clean Energy, the CLOC implementation detailed in this article provides five recommended setpoints from its optimizer. Steady-state control would require setpoint changes on the order of once every three minutes (100 total setpoint adjustments per hour). Stable operation, however, does not equate to steady-state control. To maintain *dynamic* control of net generation and plant constraints, regardless of host steam demand, the setpoints will need to be changed even more often, typically every 15 seconds, or 1200 total setpoint adjustments per hour. Clearly, 1200 setpoint changes an hour far exceed an operator's capability. This is the essential difference between an open-loop optimization, where there is reliance upon operators to implement the results of the optimization, and a closed-loop optimization, where implementation is continuous and automatic with the possibility to override the optimization results when operational conditions warrant.

Benefits Achieved

As indicated earlier, the WCE facility operates most economically if under-generation is prevented and over-generation minimized. It is therefore prudent for the plant to generate more than dispatched, but to be as close to dispatch as possible. However, there is an additional complication – ramping due to dispatch changes are normally performed in the final five minutes of the current period and the first five minutes of the next period. Despite these ramps, dispatch must be maintained for both of the one-hour periods.

Prior to the installation of the CLOC system at WCE, average over-generation during a two-month period was 4.2 MWh/h. There was also a 2.1% occurrence of under-generation. Following installation of the CLOC system, over-generation was initially reduced by 52% to 2.0 MWh/h with no under-generation incidences. As the optimization routine was further refined, over-generation was reduced by 90% to less than 0.5 MWh/h. Figure 2 summarizes these results.

THIS IS THE ESSENTIAL DIFFERENCE BETWEEN AN OPEN-LOOP OPTIMIZATION, WHERE THERE IS RELIANCE UPON OPERATORS TO IMPLEMENT THE RESULTS OF THE OPTIMIZATION, AND A CLOSED-LOOP OPTIMIZATION, WHERE IMPLEMENTATION IS CONTINUOUS AND AUTOMATIC.

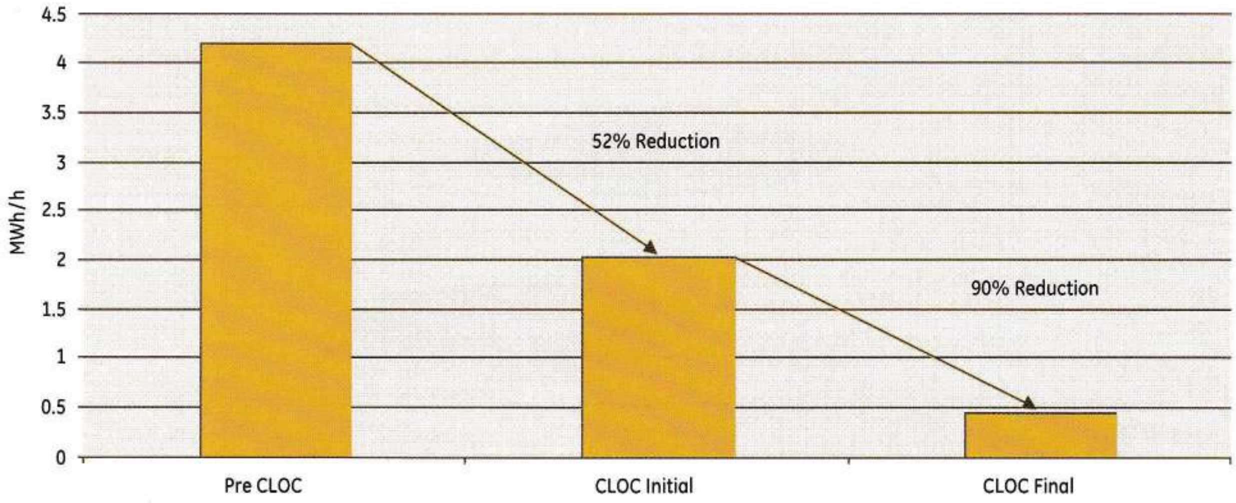


Figure 2 – Average over-generation prior to and following installation of the CLOC system.

> BY REFINING THE OPTIMIZATION ROUTINE, VARIABILITY WAS FURTHER REDUCED. THE CLOC SYSTEM WAS ABLE TO LOWER THE AVERAGE OVER-GENERATION TO LESS THAN 0.5 MWH/H WHILE PREVENTING ANY INSTANCES OF UNDER-GENERATION.

By refining the optimization routine, variability was further reduced, as noted by the extremely narrow width of the final CLOC error distribution (green). This allowed the setpoint bias to be reduced to 0.45 MWh/h, with a very low statistical likelihood of under-generation.

Another improvement was related to point-of-measurement for control actions. Prior to installation of the CLOC system, operators controlled the net generation from gross output and manually compensated for internal power consumption. After installation, the CLOC system actually controlled net generation at the point of sale, ensuring the system was making all decisions based upon actual power delivery to the grid.

The cumulative distributions in Figure 4 provide another perspective that clearly shows the dramatic improvement. Prior to CLOC, more than 93% of the over-generation was in excess of 0.6 MWh/h. In comparison, with the final CLOC implementation, less than 7% of the over-generation exceeds 0.6 MWh/h.

In summary, the CLOC system, irrespective of variations in host steam demand (and its direct impact on output from the steam turbine generator), was able to lower the average over-generation to less than 0.5 MWh/h while preventing any instances of under-generation. This is in stark contrast to the pre-CLOC average over-generation of 4.2 MWh/h and several instances of under-generation. The result is significant annual savings for WCE.

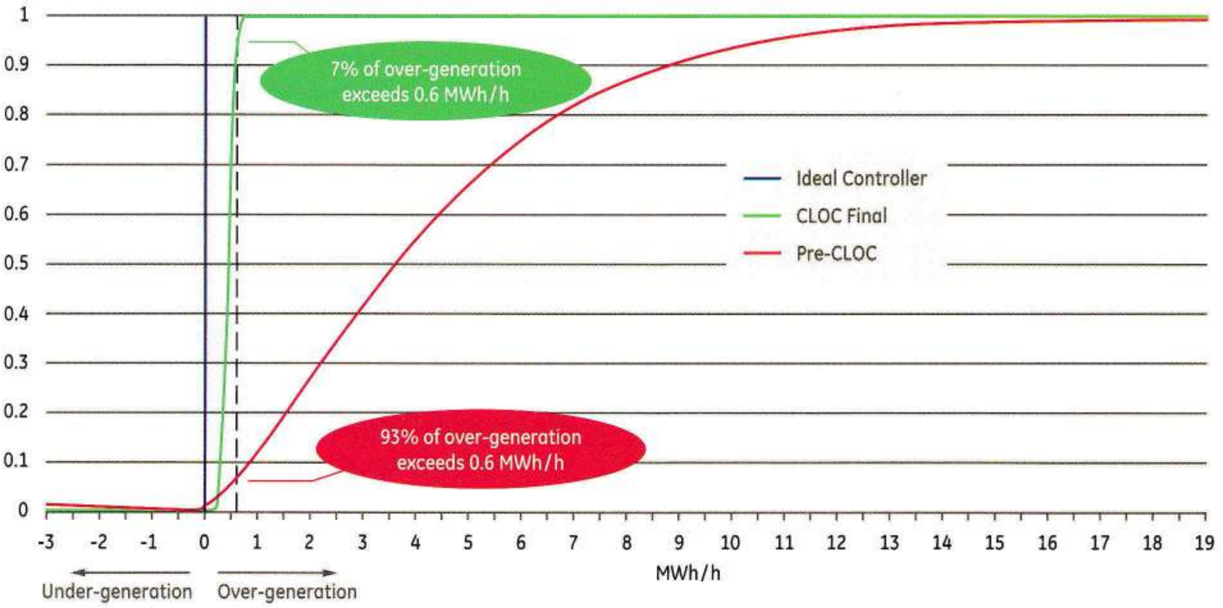


Figure 4 – Cumulative distribution of generating deviation from dispatch.

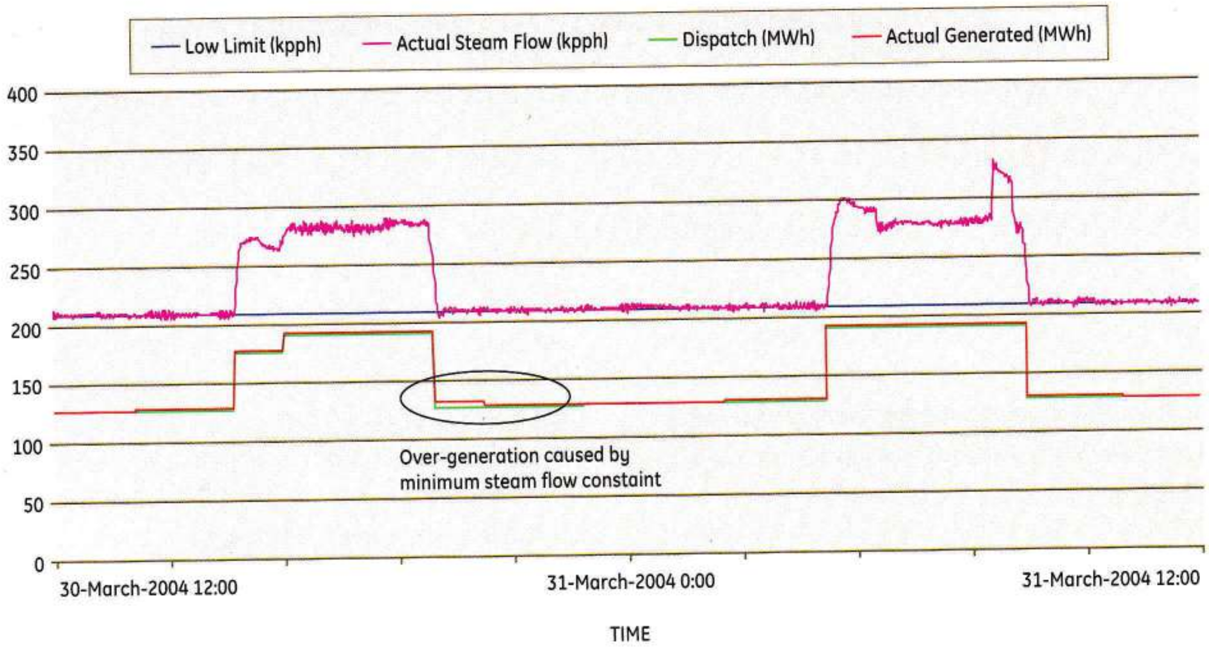


Figure 5 – **The CLOC system automatically prevents steam flow to the steam turbine generator from going below a minimum constraint. Although this results in short periods of over-generation, it prevents damage to the turbine.**

Protecting the Steam Turbine Generator

When dispatch is lowered, less and less steam will be generated by the HRSG's. While still supplying steam to the attached host, the risk exists of starving the steam turbine, causing erratic behavior of the steam throttle valves, and potentially damaging the machine. To prevent this, the CLOC system was configured with a constraint to ensure a minimum steam supply at all times, as measured by a flowmeter to the steam turbine. Figure 5 shows that the reduction in output of the gas turbine (only one was running at this time) was halted when the actual steam supply to the steam turbine hit this minimum limit. Naturally, this caused some over-generation during that period; however, it was preferable to a damaged machine and illustrates why optimization must consider many variables and – in a practical sense – can never eliminate all instances of over-generation. Thus, although the CLOC system does not completely eliminate over-generation, it effectively minimizes it.

The MW output of the gas turbine generators automatically follows rising or falling steam demand from the host. This shows the hierarchy of control priorities embedded in the CLOC system as it conducts its optimization. First, the system will prevent constraint violations. Second, dispatch will be accurately controlled. Finally, if there are sufficient degrees of freedom remaining, the fuel consumption of the facility will be minimized.

Minimizing NO_x violations

Like minimum steam flow, another important constraint in this application is NO_x levels. Though equipped with Dry Low NO_x (DLN) burners, the plant's gas turbines can exceed allowable NO_x levels when gross generation falls below a certain minimum. Unfortunately, this minimum is not constant – it is a function of ambient temperature, humidity, bleed heat, and Inlet Guide Vane (IGV) angle. Mode sequencing (fuel staging) for the DLN combustion system, however, is primarily a function of the combustion reference temperature. Other DLN influencing

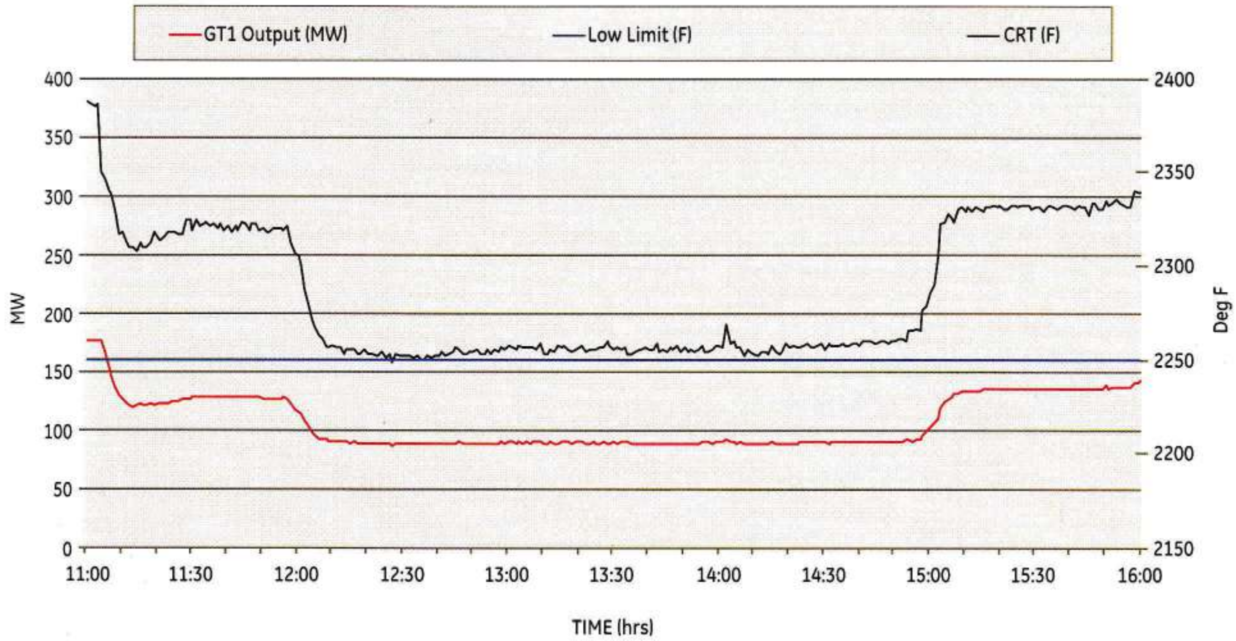


Figure 6 – **The CLOC system automatically prevents combustion reference temperature (CRT) from going below a minimum constraint. This ensures that allowable NO_x emissions limits are not violated.**

parameters available to the operators are the selection of IGV angle control and the selection of inlet bleed heat. The combustion reference temperature signal is generated by a calculation in the DLN control software. This calculated temperature represents a reference for combustor mode sequencing and fuel split scheduling, but not unit load control. It should be noted that it is not a true indication of actual machine firing temperature, only a reference for firing mode sequencing. Only in a particular full-firing mode will the DLN system be fully operational. At a lower combustion reference temperature, the DLN will close certain fuel nozzles, resulting in elevated, out-of-compliance NO_x levels.

As can be seen in Figures 6 and 7, the Combustion Reference Temperature (CRT) is closely related to the gross output of the combustion turbine. To prevent mode switching, it is imperative to maintain a minimum CRT when operating the machines. The CLOC system will lower output of the gas turbine generator, as dictated by a lower dispatch, until the combustion reference temperature reaches this lower limit. As with the minimum steam flow protection of the steam turbine, the CLOC system will first protect against constraint violations (in this case NO_x levels) before attempting to minimize voluntary over-generation.

THE CLOC SYSTEM WILL FIRST PROTECT AGAINST CONSTRAINT VIOLATIONS BEFORE ATTEMPTING TO MINIMIZE VOLUNTARY OVER-GENERATION.

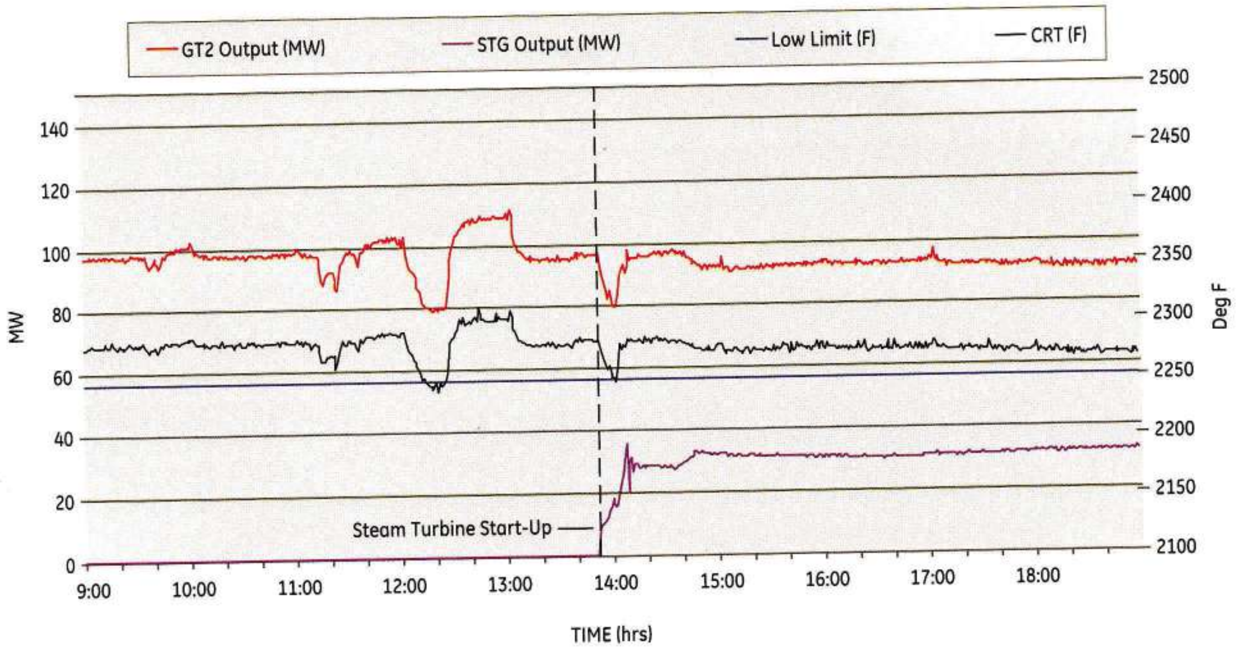


Figure 7 – As the steam turbine starts up and begins delivering power, the output of the gas turbine is automatically ramped down to maintain net generation at dispatch. When Combustion Reference Temperature (CRT) reaches its lower limit, further gas turbine output reduction is stopped to prevent NO_x emissions violation.

DEPENDENCE ON OPERATORS TO MONITOR AND ADJUST CLOC-CONTROLLED UNITS WHILE STARTING OR STOPPING ADDITIONAL ASSETS WAS ELIMINATED.

The right hand side of Figure 7 shows the effect of starting additional generating equipment (in this case, the steam turbine generator). CLOC automatically reduced output of the gas turbine generator to maintain net generation at dispatch. This reduction continued until the CRT reached its lower limit at which time the gas turbine stopped ramping down. It has been shown that this constraint control is very efficient in maintaining safe operating levels for the facility.

Operator Interactions – Starting and Stopping Assets

Dependence on operators to monitor and adjust CLOC-controlled units while starting or stopping additional assets was eliminated, because the CLOC system accounts for the net output of all generators, whether under system control or not, to ensure that dispatched generation is met accurately. This auto-adjust capability is conveyed in Figure 7, in addition to the constraint control that ensured minimum CRT was maintained.

Typically, dispatch schedules are entered for up to a week in advance by the dispatchers or by the plant operators using a Microsoft® Excel-based tool. Any dispatch change automatically triggers an alarm for the operator, and the change will not be accepted by the system unless the plant operator approves it. The use of a single database minimizes communication errors and provides a historical record for tracking purposes. The required verification by operators ensures that dispatchers do not allocate more than the plant can deliver and reduces the potential for errors based on incorrect schedule entries.

Current dispatch is transferred to the CLOC system exactly when needed. The system takes into account any ramp regulation that the plant may have with the grid owner. In WCE's case, the plant is only allowed to ramp to a different dispatch in the final five minutes of the current hour and the first five minutes of the next hour. Despite initiating a ramp in the final five minutes, the current hour's dispatch must be maintained. The CLOC system handles this constraint as well.

Figure 8 shows a 36-hour period in which the plant was dispatched. As indicated earlier, stopping an asset is easily accommodated by the CLOC system; the remaining operational assets were told automatically to make up the loss of generation and dispatch was met at the end of the period.

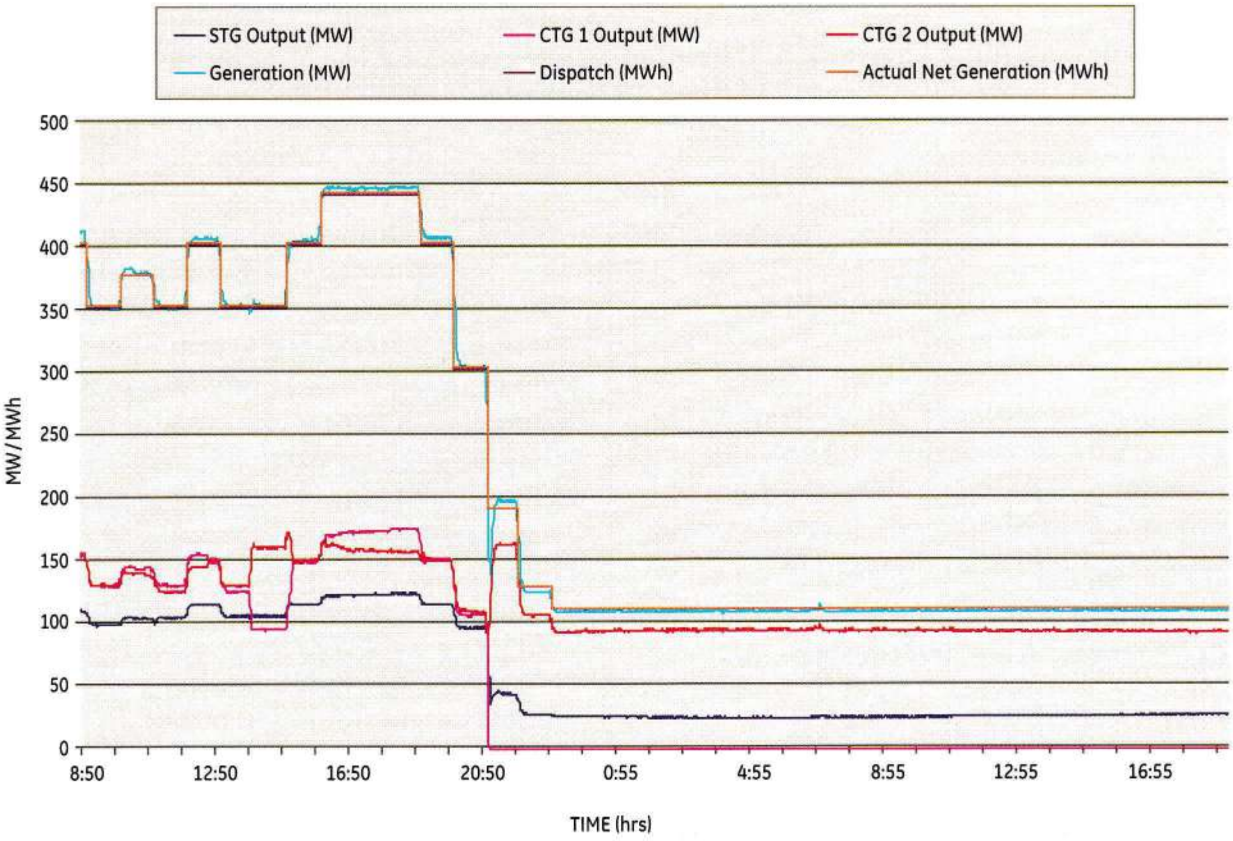


Figure 8 – This 36-hour trend shows how the CLOC System automatically adjusts the output of each machine to maintain net generation at dispatch.

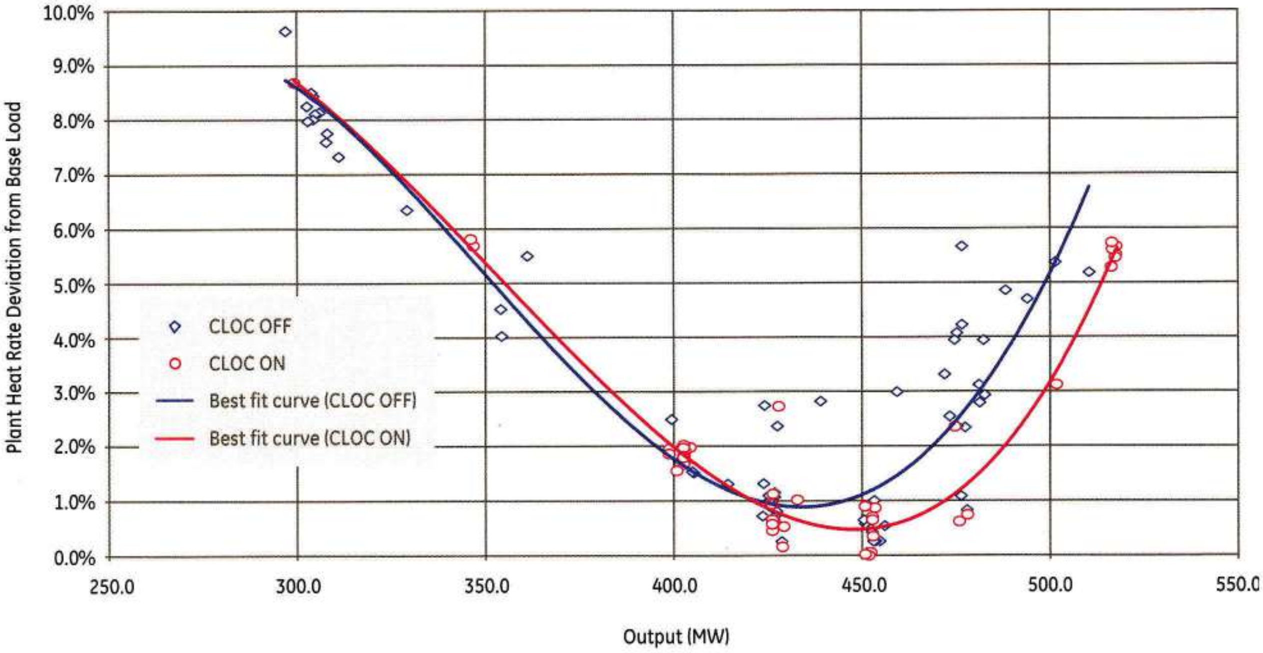


Figure 9 – **Heat Rate improvement achieved by the CLOC system when steam was not being exported. When fewer constraints are present, the optimization can manipulate variables with greater freedom, resulting in even better efficiency.**

Heat Rate Improvement

Figure 9 shows the heat rate of the facility, while under CLOC control, during a period in the summer of 2004 when the plant was not exporting steam. The optimizer becomes particularly effective at higher outputs, as can be seen from the two diverging heat rate curves. The upswing in heat rate at very high output is naturally caused by duct-firing. Figure 9 clearly indicates that if there are sufficient variables for the optimizer to manipulate, significant fuel savings can be achieved.

CLOSED-LOOP OPTIMIZATION CAN EASILY GENERATE RETURNS ON THE ORDER OF 700,000 TO 1.5MM USD PER YEAR.

Conclusion

Closed-loop control is able to address far more than just improvements in thermodynamic performance. As has been shown, GE's CLOC system was able to provide supervisory control that significantly outperformed basic regulatory control relying on manual setpoint changes. By introducing a hierarchy of control priorities, constraints such as maximum allowable NO_X emissions and minimum steam flow could be protected, voluntary over-generation could be lowered while preventing under-generation, and overall efficiency could be optimized. The use of closed-loop optimization was also shown to better maintain these benefits over time than open-loop strategies. For most plants, the combination of better generation control and closed-loop optimization can easily generate returns on the order of 700,000 to 1.5MM USD per year. ■

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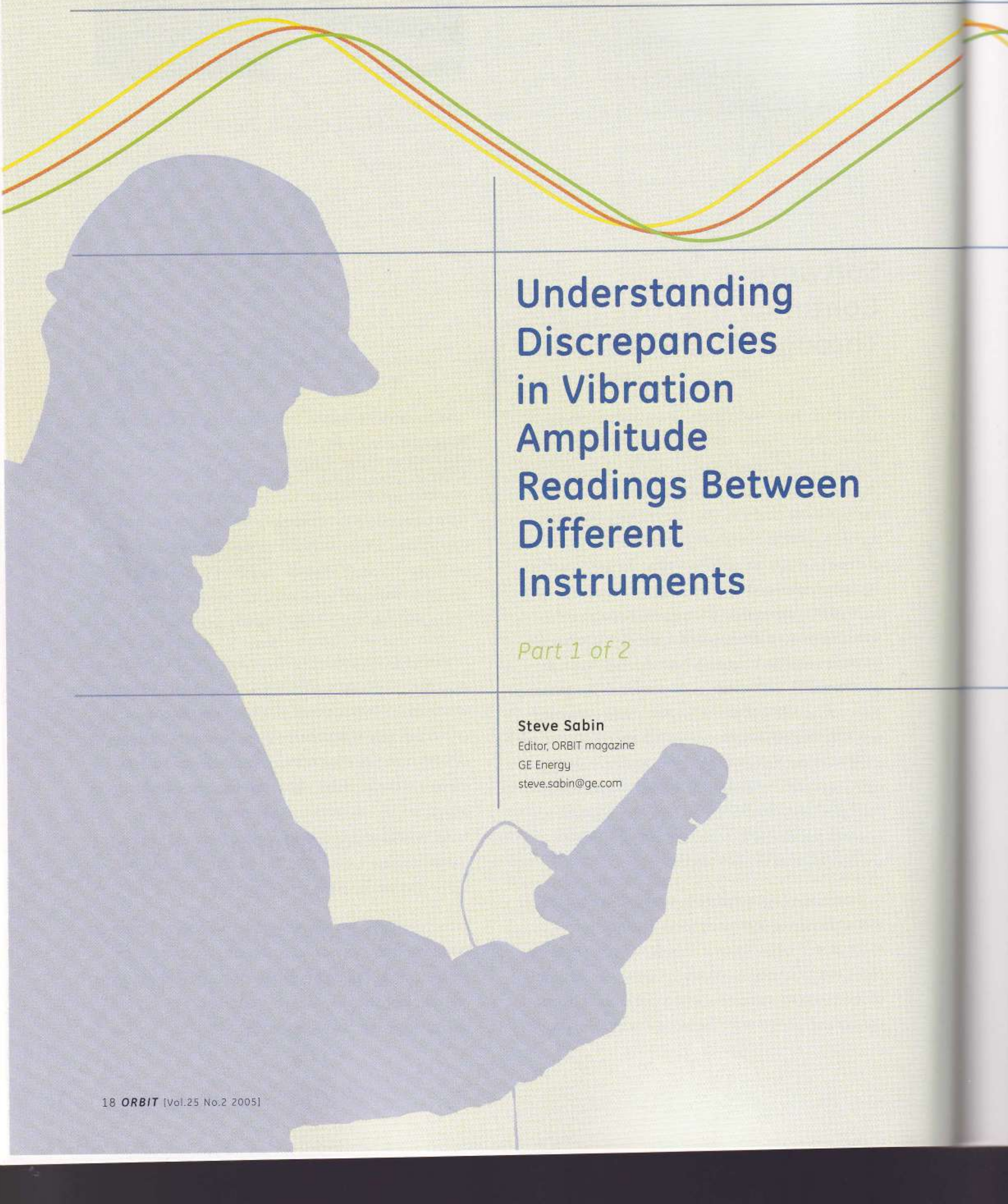
Software – Continual Improvement Through Your Feedback

If you're an avid ORBIT reader, you've noticed recent articles about our new optimization products, as well as articles highlighting our Bently Nevada® condition monitoring and diagnostics products. Software is core to many of these products. Over the last two years, our software portfolio has grown substantially. In fact, many of these products are not new; rather, we are now offering optimization and diagnostic applications from multiple acquisitions, including Bently Nevada, Enter Software, and Praxis Engineers. At the core of all these software products is deep domain knowledge of how assets operate individually, within an entire process, and even across a fleet of plants. Whether used to monitor and diagnose equipment mechanical health, machine or plant thermodynamic performance, to automatically notify operations of corrective actions, or to automatically provide optimal set points to control systems to optimize operations, our software products provide valuable benefits to users worldwide.

As the leader of our software business, I'd like to highlight that while we are continuing to develop new products, much of our current focus is on improving the usability of our existing products. Earlier this year, we sent teams of service and development personnel to audit installations at user sites around the world. For those of you who hosted these teams, thank you for your candid and constructive feedback. You identified several areas where you'd like to see changes. And, yes, we identified new issues and validated some known issues, ranging from applications to networking. Not only are we modifying code – some modifications are already available in the current product releases – we are also driving continuous improvements in our applications, development, deployment, support, and sustaining processes.

I believe that our software products are the best in the market for their particular applications. It's our challenge to satisfy the diverse needs of our thousands of users. I encourage you to provide feedback regarding our products. This may be done with our local sales and service personnel and our tech support and supporting services teams; or, you can send feedback directly to me. To foster additional interchange, we are currently planning a users conference for 2006. The location (or locations!) will be announced in the coming months.

In the meantime, be assured that we are continuing our investments to expand and continually improve our software products. Our goal is to provide you with the tools and automation to improve your business results, and I am confident that we will do so.



Understanding Discrepancies in Vibration Amplitude Readings Between Different Instruments

Part 1 of 2

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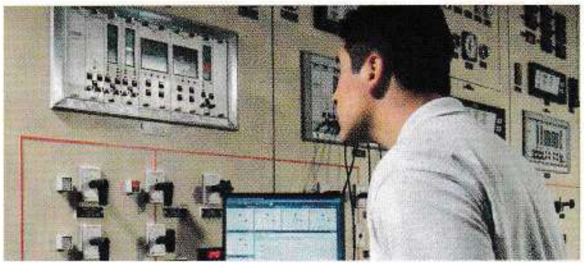
Introduction

Numerous times each year, customers contact our sales and service professionals with a common question: "I took a vibration reading with a portable diagnostic instrument, but it does not agree with what I am seeing on my Bently Nevada® monitor. Why?"

Often, customers assume that there must be a problem with the monitor, the diagnostic instrument, or both. However, this is rarely the case. Instead, there are some very straightforward reasons why there are often discrepancies in vibration readings – particularly peak-to-peak amplitude readings – between two instruments. In this first installment of a 2-part article, we explore those differences, building on and updating material that was originally published in the article "Monitoring versus diagnostics – why do peak readings differ?" in the March 1994 issue of ORBIT.



4 Key Categories

The reasons why readings differ between instruments can generally be divided into four basic categories as summarized below and as shown in Figure 1:

1. Dissimilar inputs
2. Dissimilar signal processing prior to amplitude detection
3. Dissimilar amplitude detection algorithms
4. Calibration/indication problems

This article discusses each of these in order, illustrating how each can contribute to discrepancies in the indicated amplitude of a vibration signal. In part 1, we focus on the first two categories: inputs and signal processing. In part 2, which will appear in the next issue of ORBIT, we examine the last two categories: amplitude detection and indication/calibration.

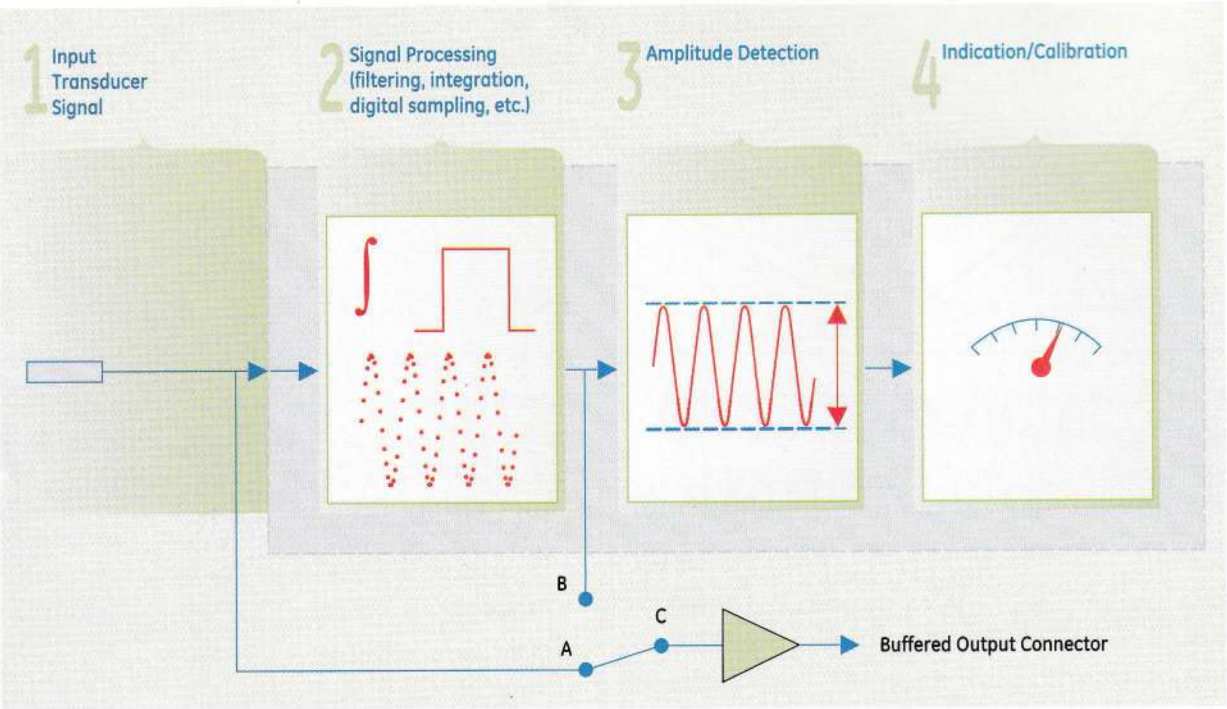

1 Input Transducer Signal
2 Signal Processing (filtering, integration, digital sampling, etc.)
3 Amplitude Detection
4 Indication/Calibration
B
C
A
Buffered Output Connector

Figure 1 – **By considering the four stages of a signal as it travels through an instrument, it is easier to understand and isolate discrepancies in readings between two devices.**

Table 1 –

WAVEFORM AMPLITUDE CONVENTIONS USED IN BENTLY NEVADA INSTRUMENTATION

Peak-to-Peak (pp)	The difference between the maximum positive-going and negative-going peaks in a periodic waveform during one complete cycle.
Zero-to-Peak (pk)	The pp value of a vibration signal divided by two (pp/2). Also referred to as "true peak."
Root Mean Square (RMS)	A measurement of the effective energy content in a signal. Mathematically, the RMS value of a waveform f(t) is defined as $$A_{RMS} = \sqrt{\frac{1}{T}\int_{t_0}^{t_0+T} f(t)^2\,dt}$$ where T is the period (one complete cycle) of the waveform*.

* To accommodate all expected periods in generalized waveform inputs to an instrument, T is typically chosen for computation purposes to coincide with the lowest frequency measurable by the instrument. Thus, an instrument with a bandwidth down to 0.5 Hz would use $T = 2$ seconds.

Definitions

Because Bently Nevada monitoring instruments typically use proximity probe inputs that measure the total back-and-forth displacement of the shaft, peak-to-peak (pp) is the most commonly encountered engineering unit when dealing with our instruments. However, this article will also discuss zero-to-peak (pk) and RMS readings since they are frequently encountered as well, particularly in portable instruments.

One of the primary reasons that confusion arises when making amplitude measurements is that many instruments (such as portable analyzers/data collectors) provide the user with multiple configuration options for peak detection. For example, one well-known manufacturer of portable data collectors provides the following four options on several of their models:

- Digital Overall
- Analog Overall
- True Peak
- Average Peak

Compounding this, different manufacturers use not only different detection algorithms/circuits, but different nomenclature such as "calculated peak," "peak," "derived peak," "pseudo peak," "overall peak," and others. Clearly, a user needs to understand the specific algorithms and conventions used when interpreting amplitude readings, and in part 2 of this article we will investigate in much greater detail some of the algorithms used for these readings, comparing them to the algorithms used in Bently Nevada instruments.

Throughout this article, we will use the Bently Nevada instrumentation conventions for describing signal amplitudes, which are summarized in Table 1.

Figure 2 illustrates these concepts for two types of waveforms: a pure sine wave and a generalized complex signal consisting of several sinusoids of varying frequencies and phases.

While the pp values are obvious for both waveforms, the pk and RMS values merit further discussion.

As noted in Table 1, the convention used for pk in Bently Nevada instrumentation is simply the pp value divided by two. For the symmetrical sinusoid of Figure 2A, the maximum amplitude traversed by the wave is the same in both the positive and negative directions and is equal to pp/2. However, the waveform of Figure 2B is non-symmetrical. That is, its positive peak is not equal to its negative peak. Some manufacturers define pk as the larger of either the maximum negative-going or positive-

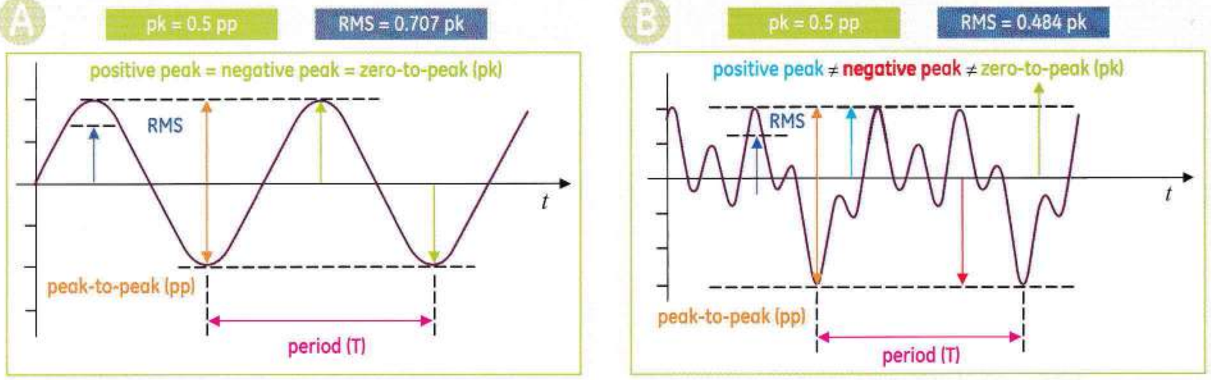


Figure 2 – **Peak-to-peak (pp), zero-to-peak (pk), and RMS are the most commonly used conventions for expressing the amplitude of vibration waveforms. The conversion between RMS and pk is only equal to $1/\sqrt{2}$ (0.707) for a pure sine wave (A). For a more complex signal (B), the equation of Table 1 must be used to compute the RMS value. The conversion between pp and pk can differ between manufacturers and becomes apparent if the waveform is asymmetrical (B). When using the Bently Nevada instrumentation convention of pk = pp/2, the pk value may not be equal to either the positive or negative peaks on an asymmetrical waveform.**

going peak. Thus, they would return a peak value for the waveform of Figure 2B as 3.0, while a Bently Nevada instrument would return a peak value of 5/2 = 2.5, resulting in a 20% discrepancy between the readings. There is no right or wrong convention, and when a symmetrical waveform is used, both conventions will provide identical results. Discrepancies occur when the waveform is nonsymmetrical, as is the case for most real vibration waveforms except when filtered to a single frequency (such as 1X). Thus, real vibration waveforms may yield different peak readings simply by virtue of the different conventions used between two instrument manufacturers.

RMS measurements are a frequent area of misunderstanding and lead to many of the discrepancies seen in the field. Many practitioners have been taught that pk is simply RMS × $\sqrt{2}$ (1.414) and many instruments provide a setting that returns such a value, sometimes referred to as "derived peak" or "calculated peak." While this relationship between peak and RMS is true for a pure sine wave, it is not true for a generalized waveform with complex frequency content. Thus, use of the word "peak" for such measurements is an unfortunate and potentially misleading choice of nomenclature; it is really more appropriate to think of these measurements as "scaled RMS." As examples of the complete independence of true peak values from RMS values, consider the following:

- The RMS value of a square wave is 1.0 × pk.
- The RMS value of a triangle wave is 0.577 × pk.
- The RMS value of the waveform in Figure 2B is 0.484 × pk.

Because RMS and true peak are completely unrelated, instruments capable of accurately providing both readings must employ one type of circuit or algorithm for computing true peak and a distinctly different one for computing RMS.

We will have much more to say about the topic of "derived peak" in part 2 of this article when we discuss and compare the various algorithms and circuits used for computing RMS and pk waveform amplitudes.

1. Dissimilar Inputs

The first and most fundamental part of comparing readings from different instruments is to ensure that you are using an *identical* input to each instrument. Until this has

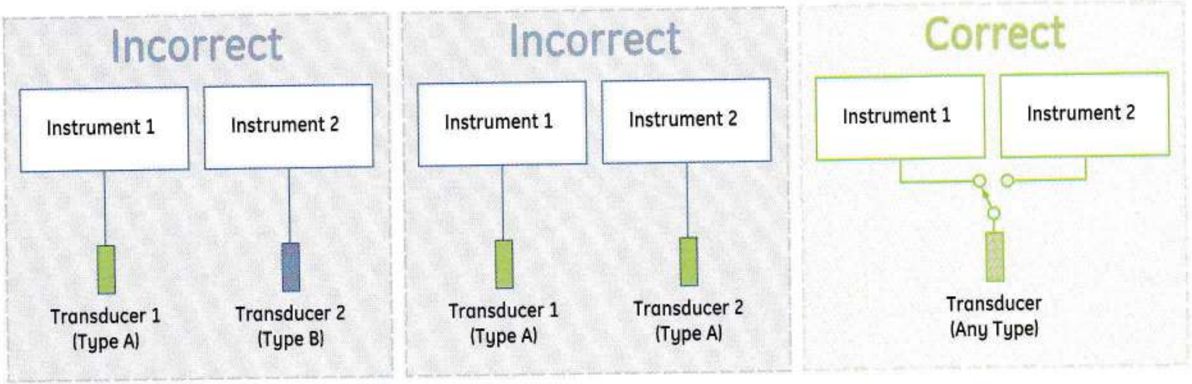


Figure 3 – **When comparing readings from separate instruments, it is imperative to introduce the same transducer signal to each (right). Merely using the same type of transducer (center) is not sufficient and will almost always lead to discrepancies in readings. Nor is it appropriate to use a different type of transducer (left) and simply convert the signal to consistent units, such as via integration.**

been thoroughly and completely confirmed, it is pointless to proceed. This simple step accounts for quite a few of the discrepancies in readings seen in the field, because users are not comparing "apples with apples." Ensure that you are actually using the same transducer to provide an input signal to each instrument. This means not just the same *type* of transducer, but the same physical transducer (Figure 3).

Often (but not always) a Bently Nevada monitoring system will be using eddy-current proximity probes as the input type. These probes measure the relative displacement between the probe's mounting location (often the bearing housing or machine case) and the shaft. Customers will sometimes suggest that all they have to do is integrate their velocity signal or double-integrate their acceleration signal to obtain displacement units, allowing them to compare casing measurements with those from proximity probes. However, although this may result in readings with the same engineering units, the physical measurements being made are quite different (Figure 4). Seismic transducers measure casing motion relative to free space. Proximity probes measure shaft motion relative to the probe's mounting. Integration of a casing-mounted velocity transducer signal merely gives the amount of casing displacement which is *not* the same as the relative displacement between the shaft and the probe's mounting (usually the machine case). Thus, while comparing these two signals to one another does have a valuable role in machinery diagnostics, it is not appropriate to compare them when attempting to see if two instruments agree with one another.

Even when the input to the permanent monitoring system is a permanently affixed seismic transducer, it is still inappropriate to use a different transducer (such as a hand-held or magnetically mounted seismic sensor) for the other instrument. Enough variation will often exist between the mounting methods of permanent, stud-mounted transducers and a hand-held or magnetically affixed sensor to give noticeable discrepancies in readings. In addition to differences contributed by transducer mounting methods, the differences in mounting *locations* can be pronounced. The vibration response can differ

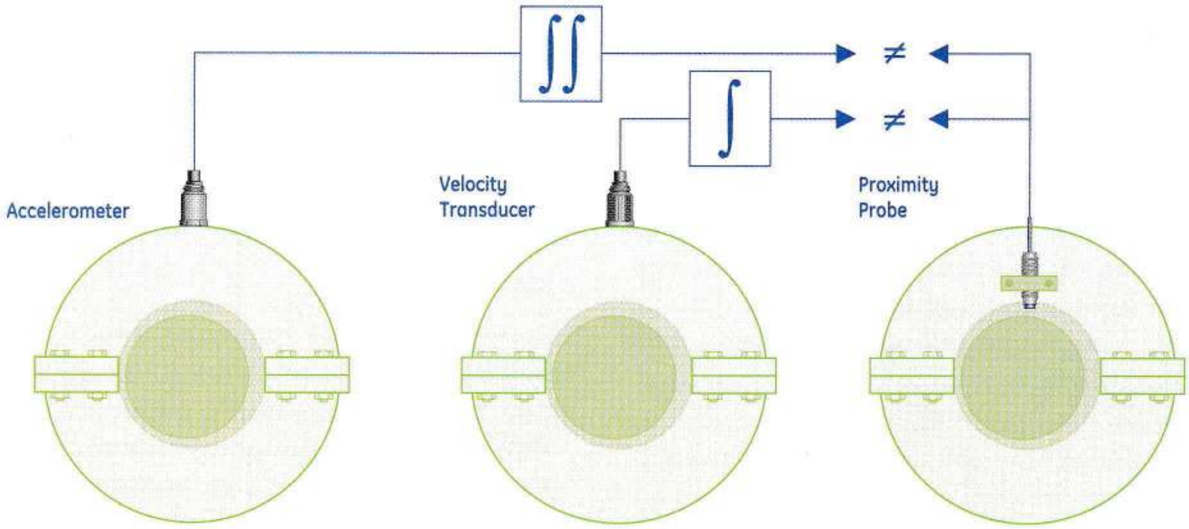


Figure 4 – **Although integration yields measurements with the same engineering units, they are not equivalent measurements because a proximity probe measures the relative motion between the probe's mounting surface and the shaft, while seismic transducers measure the absolute motion of the transducer relative to free space.**

greatly even when two transducers are located very close together. They must be oriented along the same axis, use the same method of attachment, and be attached to a part of the machine with identical stiffness. For example, many machines are supplied with a specially machined "flat spot" designed to accommodate portable or permanent seismic transducers. However, this location is rarely large enough to accommodate two transducers side-by-side. Placing one transducer on the flat spot and another transducer just a few inches away can result in different readings for the reasons mentioned above.

Next, we examine the second of four categories for dissimilar amplitude readings: differences in signal processing that occur prior to amplitude detection.

2. Dissimilar Signal Processing Prior to Amplitude Detection

Once you have confirmed that the identical signal is being introduced to each instrument, you must then understand any intermediate signal processing that is to be performed prior to the amplitude detection portion of the instrument. Typically, this intermediate signal processing may include filtering, integration, and digital sampling.

Anti-Alias Filtering

Many instruments today perform their functions digitally. Digital signal processing theory shows that in order for a signal to be represented faithfully, the sampling frequency (known as the Nyquist rate) must be at least twice the highest frequency present in the analog signal. For example, if the sampling frequency of an instrument is 1000 Hz, the highest frequency that can be present in the analog signal is 500 Hz. Digital instruments use an analog filter (known as an anti-alias filter) to limit the high-frequency content of the incoming signal before sampling. In the example above, the anti-alias filter is designed to reject frequencies above 500 Hz, passing only those frequencies below 500 Hz to the digital sampling circuitry of the instrument.

It is important to understand where the anti-alias cutoff frequency occurs for your instrument. Depending on the amplitude and phase of the frequencies that are filtered out, this can have a dramatic effect on the amplitude measured by the instrument. Such filtering will provide a very different waveform amplitude when compared with an analog instrument that does not employ any filtering of the signal, or a digital instrument with extremely broad bandwidth such as a digital oscilloscope capable of capturing frequencies in the Gigahertz range. Also, it is important to note that many instruments provide different anti-alias settings for each measurement. For example, a single incoming signal providing an overall (unfiltered) measurement, bandpass filtered measurement, synchronous waveform measurement, and asynchronous waveform measurement may have different anti-alias settings for each of these four measurements.

Many times, the sampling frequency in devices such as portable data collectors/analyzers is a user-configurable option, designed to balance storage limits with diagnostic needs (higher sampling rates give larger bandwidth and higher resolution at lower frequencies, but require more memory). By configuring the sampling frequency, the anti-alias filter will automatically be set by the instrument. Thus, you can generally determine the anti-alias cutoff frequency by looking at the instrument's sample rate setting. For example, if the instrument is set to sample at 10 kHz, the anti-alias filter will be slightly less than one-half of this frequency (approximately 5 kHz or 300,000 cpm). For instruments where the sample rate is not configurable or is unknown, consult the manufacturer.

Some data collectors will also allow the user to independently choose the spectral resolution which affects the amount of memory required for each vibration sample collected. When "reconstructing" the analog waveform from the digital samples, both the spectral resolution and the maximum frequency will affect the results.

To understand the effect that an anti-alias filter will have when the incoming signal has significant frequency content above the anti-alias cutoff frequency, consider the example of Figure 5. In Figure 5A, sinusoids of 100, 200, and 500 Hz are shown. Each sinusoid is identical in phase

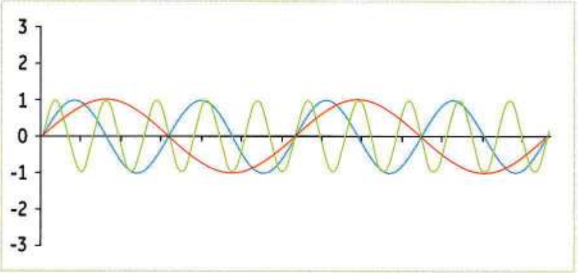


Figure 5A – **Three sinusoids of equal amplitude and phase, differing only in frequency (100 Hz, 200 Hz, 500 Hz). Amplitude of all sinusoids is 1.0 pk.**

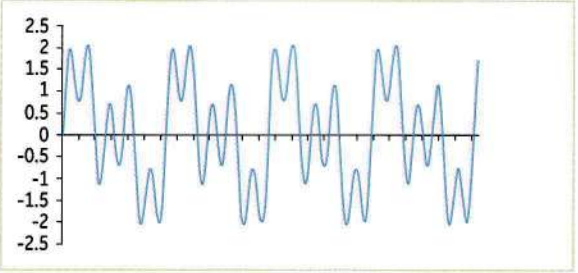


Figure 5B – **The resulting waveform when all three sinusoids of Figure 2A are summed. Amplitude is approximately 2.1 pk.**

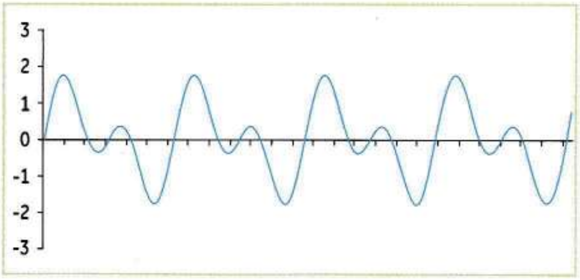


Figure 5C – **The resulting waveform when an anti-alias filter with a 400 Hz cutoff frequency is introduced. Only the 100 Hz and 200 Hz components remain and waveform amplitude is reduced to approximately 1.7 pk.**

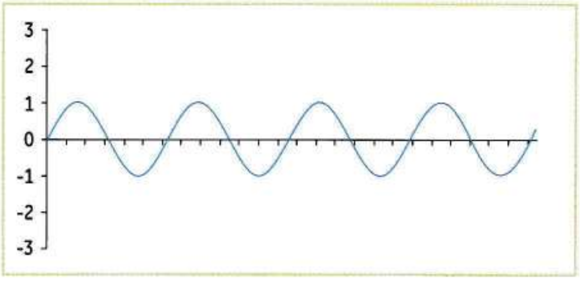


Figure 5D – **The resulting waveform when an anti-alias filter with a 150 Hz cutoff frequency is introduced. Only the 100 Hz sinusoid is left, with an amplitude of 1.0 pk.**

and amplitude (pk = 1.0), differing only in frequency. Figure 5B shows the composite waveform that results when these sinusoids are summed, creating a waveform with pk amplitude of approximately 2.1. Assuming an "ideal" anti-alias filter that completely removes all frequencies above the cutoff and has no effect on the amplitude or phase of frequencies below the cutoff, the introduction of such a filter with a 400 Hz cutoff frequency removes the 500 Hz component and reduces the original waveform pk amplitude by approximately 19% (Figure 5C). Lowering the anti-alias filter to 150 Hz removes both the 200 and 500 Hz components, reducing the original pk amplitude by approximately 52% and leaving only a 100 Hz sinusoid (Figure 5D).

In practice, actual vibration waveforms are generally far more complex, composed of many frequencies, each with a different phase relationship and amplitude. Depending on the amplitude and phase relationships between frequency components, filtering out a specific frequency may decrease or *increase* the overall amplitude. This is often the cause of much confusion, because users will sometimes reason, "How can I 'remove' signal content and end up with a larger amplitude?" The answer lies in the way that waves add. Depending on the phase, waves can add constructively or destructively. Consider the extreme case of two sinusoids, equal in amplitude and frequency, but exactly 180° out of phase. When summed, they will completely cancel each other and the resulting waveform will have zero amplitude. Thus, even though we start with two waveforms with non-zero amplitudes, by adding them together, we end up with a smaller amplitude (in this case, zero). In fact, this is precisely the theory behind the new "noise canceling" headphones now on the market.

As another example, consider a square wave $f(t)$ with a pk amplitude of A. This waveform can be mathematically represented as an infinite sum of sinusoids (Equation 1) consisting of a fundamental frequency (1X) and its odd harmonics (3X, 5X, 7X, etc.) that decrease proportionately in amplitude.

$$f(t)=\frac{4A}{\pi}\sum_{n=1,3,5,}^{\infty}\frac{1}{n}\sin nt=\frac{4A}{\pi}\left\{\sin t+\frac{1}{3}\sin 3t+\frac{1}{5}\sin 5t+\frac{1}{7}\sin 7t+\ldots\right\} \qquad [1]$$

If we low-pass filter the square wave such that all frequencies higher than 1X are removed and only the fundamental frequency remains, we are left with Equation 2

$$f(t)_{filtered}=\frac{4A}{\pi}\sin t \qquad [2]$$

which has peak amplitude $4A/\pi$. Notice that this is 27% *larger* than the pk amplitude of the original square wave (see Figure 6). Admittedly, a square wave is not routinely encountered in vibration analysis, but it does serve to show how a waveform and its constituent frequency components sum in a complex fashion, adding in some places and canceling in others. We occasionally see real vibration waveforms in practice that have slightly higher filtered amplitudes than unfiltered amplitudes. Thus, while the removal of frequency components will generally reduce the overall amplitude, this may not always be the case and does not necessarily indicate a problem with the instrumentation.

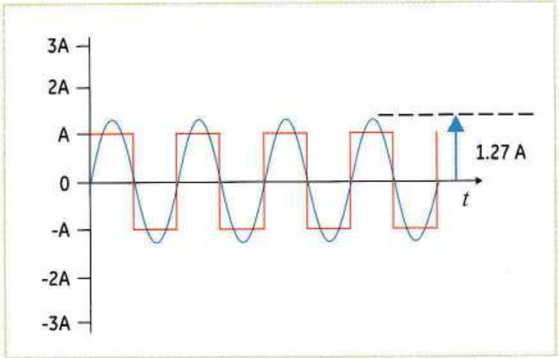


Figure 6 – **The pp amplitude of a square wave is actually less than the pp amplitude of its fundamental (1X) component. In the same way, although not common in vibration diagnostics, a filtered amplitude can occasionally be larger than the unfiltered overall amplitude.**

Filtering Effects on Phase

Above, we discussed the effects of entirely removing (or attenuating the amplitude of) certain frequency components from a composite waveform. However, it must be remembered that filters modify not only the *amplitude* of frequency components, but the *phase* as well. These phase relationships of frequency components are just as important as their amplitudes in determining the shape and amplitude of the resulting waveform. Because vibration analysts typically only look at the amplitude of spectrum components, it is easy to forget the importance of phase and its effect on the resulting complex waveform in the time domain. Indeed, two waveforms with identical amplitude spectra can have very different waveform shapes and pp amplitudes. To appreciate this, consider the waveform of Figure 5B. Its amplitude spectrum is shown in Figure 7A, corresponding to the three discrete sinusoids of Figure 5A. Assume now that we have a filter which leaves the amplitude of each frequency component unchanged and merely shifts the phase. The resulting waveform, as shown in Figure 7B, has a very different shape, symmetry, and pp amplitude from the waveform of Figure 5B and serves as a reminder that identical amplitude spectrums do not always correspond to identical timebase waveforms.

Thus, be aware, as shown in this example, that filtering can affect the amplitude and shape of the original waveform not only by altering the amplitude of frequency components, but the phase as well.

Although certain digital filters with any desired amplitude roll-off can be designed with constant phase shift, this is not possible for analog filters. Indeed, with analog filters, the steeper the amplitude roll-off, the more phase distortion that is introduced near the cutoff frequency. A typical 4-pole low-pass filter with a 10 kHz cutoff frequency is shown in Figure 8. The phase distortion exceeds 15° for frequencies above 1 kHz and is a full 180° at the cutoff frequency (- 3 dB point).

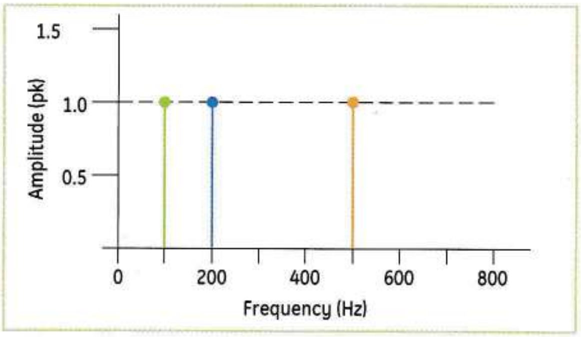


Figure 7A – **Amplitude spectrum for the waveforms of Figures 5B and 7B. Note that only the amplitudes of the frequency components are shown, not their phase relationships to one another.**

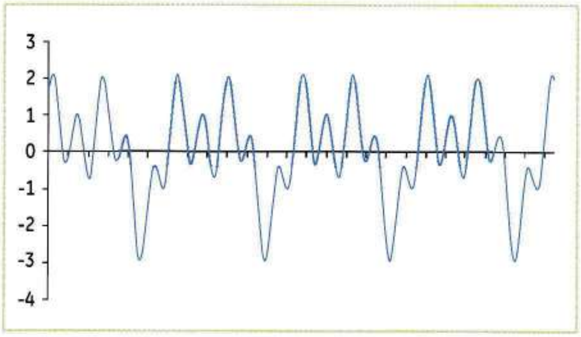


Figure 7B – **Resulting waveform when the phase of the 200 Hz and 500 Hz frequency components in Figure 5B are shifted by -270 ° and -315° respectively. Note the changes in waveform shape, pp amplitude, and symmetry that occur.**

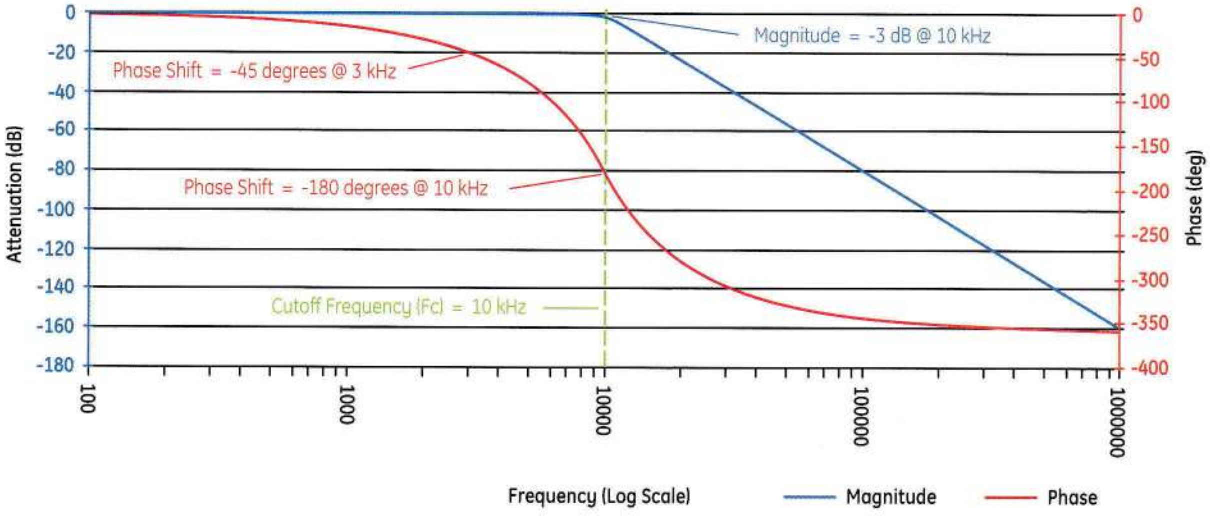


Figure 8 – **Amplitude and phase response for a 4-pole low-pass filter. Although the cutoff frequency is at 10 kHz, appreciable phase distortion occurs for frequencies above several thousand Hz. For example, a 3 kHz frequency component will undergo a phase shift of approximately 45 degrees, even though its amplitude remains unchanged. Such phase changes can have a significant effect on the filtered waveform, including its peak-to-peak amplitude.**

Other Filtering

Depending on the type of transducer input, additional digital or analog filtering may be performed on the signal besides just anti-alias filtering. This is often the case with accelerometer and velocity transducers. For example, aeroderivative gas turbines typically use high-temperature accelerometers on the machine's casing, and to prevent the extremely high amplitude blade-pass frequencies from "swamping" the rotor-related frequencies, low-pass or band-pass filtering is often done either before the signal enters the monitoring system (such as in the transducer interface module), or inside the monitoring system. Clearly, such filtering affects the waveform shape and amplitude.

Other Signal Processing

In addition to filtering, integration is a very common type of signal processing performed by vibration measurement instruments. Some instruments allow the user to perform integration either before or after filtering. While it can be shown mathematically for ideal integrators and filters that the order in which these operations are performed does not matter, practical circuit implementations are non-ideal. Thus, integration prior to filtering can yield different results than vice-versa. In particular, integration prior to high-pass filtering may amplify low frequency components that are not directly related to machine condition, thereby reducing overall signal quality. For this reason, with few exceptions, Bently Nevada monitors generally only permit the user to integrate after filtering (see Table 2). When comparing two instruments, ensure that the order in which they filter and integrate are the same.

Buffered Outputs

All Bently Nevada permanent monitoring systems provide buffered output connectors, generally on the front of the monitoring system. Analysis instruments, such as portable data collectors and oscilloscopes, are routinely connected to these outputs. In fact, it is recommended that when comparing a portable or bench instrument to your Bently Nevada monitor, you use these buffered output connectors to ensure an identical signal is being introduced to the instrument as to your Bently Nevada monitor. These outputs also have the advantage of being isolated so that any inadvertent wiring problems will not affect the incoming signal to the monitor.

In the vast majority of cases, these outputs represent the unconditioned ("raw") transducer signal coming into the monitor. However, there are some exceptions with seismic monitoring channels on our 3300 and 2201 monitoring systems where these outputs can be configured for either conditioned or unconditioned signals (see Table 2).

Referring back to Figure 1, we illustrate the difference between conditioned and unconditioned outputs. When points A and C are connected, the signal at the buffered output is identical to the incoming transducer signal. This is referred to as "unconditioned." However, when points B and C are connected, the buffered output will reflect any intermediate filtering and/or integration being performed. This is referred to as "conditioned." Thus, be certain that you understand what type of signal is present at the buffered output connectors of your 3300 or 2201 monitoring system seismic channels before assuming that it is identical to the "raw" input transducer signal. If in doubt, consult the documentation supplied with your system or contact our nearest sales and service office for assistance. Also, some applications (particularly those for aeroderivative gas turbines) will pre-filter the transducer signal before it enters the monitoring system, as mentioned above. Occasionally, both the "raw" and "pre-filtered" signals will be brought into the monitoring system and made available via separate buffered output connectors.

Table 2 –

SUMMARY OF BUFFERED OUTPUT SIGNAL PROCESSING FOR SELECTED BENTLY NEVADA CONTINUOUS MONITORING SYSTEMS

System	Buffered Output Convention	Filtering/Integration Order	Buffered Output Impedance
3500	Unconditioned	Filtering always before integration	550 Ω
3300	User configurable for conditioned or unconditioned*	User configurable*	100 Ω
1701	Unconditioned	Filtering always before integration	200 Ω
2201	User configurable for conditioned or unconditioned**	User configurable**	100 Ω
7200	Unconditioned	Filtering always before integration	100 Ω
9000	Unconditioned	Filtering always before integration	3300 Ω
1900	Unconditioned	Filtering always before integration	300 Ω (1900/55) 500 Ω (1900/25 and 1900/27) 550 Ω (1900/65)
1800	Unconditioned	Filtering always before integration	9090 Ω

* User configurable for 3300/25, 3300/26, and 3300/55 monitor modules only.

** User configurable for acceleration and velocity channels only.

Output/Input Impedance

Another area in which discrepancies can be introduced relates to signal loss when connecting the output of instrument A to the input of instrument B. This occurs because a voltage divider is formed and the signal loss between the two devices is given as

$$\text{Signal Loss } (\%) = \left[1 - \frac{Z_{in}}{Z_{out} + Z_{in}}\right] \times 100 \qquad [3]$$

where Z_{out} is the output impedance of instrument A and Z_{in} is the input impedance of instrument B. To keep the signal loss to 1% or less, the ratio of input impedance to output impedance should be 100:1 or greater.

For example, if the buffered output from a Bently Nevada 1800 series relative vibration transmitter (scale factor = 200 mV/mil) is connected to a device with a relatively small input impedance (say, 100kΩ), the loss of signal can be found using Table 2 and Equation [3] as follows:

$$\text{Signal Loss } (\%) = \left[1 - \frac{Z_{in}}{Z_{out} + Z_{in}}\right] \times 100 = \left[1 - \frac{100{,}000}{9090 + 100{,}000}\right] \times 100 = 8.33\%$$

Thus, an 1800 series transmitter measuring 5 mils of pp vibration would provide an output signal of 5 mils × 200 mv/mil = 1 volt pp. However, 8.33% of this signal will be lost, resulting in only 0.916 volts at the input of the other instrument. Assuming no other sources of discrepancy are introduced, this other instrument would only indicate a vibration amplitude of 4.6 mils pp.

Summary

Because discrepancies in vibration amplitude readings from different instruments are a common source of questions from customers, understanding how these discrepancies arise is valuable for anyone tasked with interpreting the meaning and severity of such readings. In this article, we have shown that many discrepancies can be grouped into four primary categories, starting with the necessity for ensuring that the input signal to both instruments is truly identical and proceeding to some of the intermediate signal processing that typically occurs prior to amplitude detection. In particular, we have examined the effect of filtering on a signal's content and the ways that both changes in spectral amplitude and spectral phase can alter the shape and overall amplitude of a waveform.

We have also defined the conventions used in Bently Nevada instrumentation for describing a waveform's amplitude and discussed the differences in conventions used by other instrument manufacturers.

In part 2 of this article, slated for the next issue of ORBIT, we will continue with an in-depth examination of the circuits and algorithms actually used in a number of instruments to compute pk and pp amplitude, showing how they can account for dissimilar readings. We then conclude with a discussion of indication and calibration considerations. Armed with this information, vibration analysts and machinery engineers will be better prepared to understand the reasons why amplitude measurements can differ and how to interpret such differences.

Low Frequency Velocity Sensor

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The new 330505 Low Frequency Velocity Sensor is specifically designed for measuring stator frame and bearing housing vibration on hydro units.

Many of today's hydroelectric turbine-generators operate under conditions that introduce significant mechanical and electrical stress on the assets – stresses that are a direct result of a power market that requires tremendous operational flexibility. As detailed in the Second Quarter 2004 issue of ORBIT, we now offer a comprehensive condition monitoring solution to fully address these important assets and integrate all of their monitored parameters into a single system.

Key measurements within this offering are stator frame and bearing housing vibration. Today, we are pleased to introduce the new Bently Nevada® Low Frequency Velocity Sensor, specifically designed for these important measurements. Intended for hydro applications to detect vibration of the stator core, stator frame, and bearing supports, the sensor measures absolute vibration within the range of 0.5Hz to 1.0kHz. Its two-wire design uses moving-coil technology and embedded signal conditioning circuitry to provide a voltage output directly proportional to the vibration velocity.

Stator core and frame vibration can cause fretting and damage to the winding insulation. Core and frame vibration can be caused by uneven air gap, manufacturing flaws, or a weak support structure. To detect these problems before serious damage occurs, the seismic sensor is mounted on the outer diameter of the stator core and frame.

Bearing housing vibration is likewise an important measurement, alerting operators to premature failure of machine components and other significant machine problems. In addition, housing vibration can also distort levels of vibration measured by shaft-observing proximity probes, and having both the shaft-relative and bearing-absolute vibration signals available can be a valuable diagnostic tool. Bearing frame vibration can be caused by a weak support structure, resonances, and loads originating within the machine or other nearby sources. The sensor is mounted to the bearing housing either as a stand-alone measurement or in the same orientation as existing proximity sensors.

The sensor is connected to the Bently Nevada 3500/46M Hydro Monitor, for a solution that meets the requirements of International Organization for Standardization (ISO) Standard 10816-5 (Mechanical Vibration – Evaluation of machine vibration by measurements on non-rotating parts – Part 5: Machine sets in hydraulic power generating and pumping plants). In addition, powerful System 1® Optimization and Diagnostic Software provides comprehensive condition monitoring capabilities including advanced plots and sophisticated data analysis tools.

Due to the nature of high amplitude, low frequency velocity events, the 330505 Low Frequency Velocity Sensor is not recommended for automated machinery protection. It is designed to provide an early warning of pending machinery problems and to assist in diagnostics. Detecting problems early, before serious damage occurs, facilitates condition-based maintenance and allows time to plan for repairs before scheduled outages.

You can learn more about our hydro condition monitoring solutions and this new sensor by requesting literature via our reader service card, by visiting www.bently.com, or by contacting your nearest sales professional.

learn more online at
http://www.gepower.com/o&c/hydro

OK Limits for Impact Events

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One of the challenges in designing a robust machinery monitoring system is to be able to differentiate between legitimate malfunctions that often result in large amplitudes from the sensor, and a malfunction with the sensor itself. The ability to differentiate malfunctions is a result of not only the sensor, but how the sensor is applied. For example, a proximity probe used to measure radial vibration may see large changes in its dynamic signal as vibration amplitudes increase, and an average gap voltage that will generally not go out of the transducer's linear range unless the sensor has a fault. But, the same transducer applied to make an axial thrust position measurement primarily senses changes in average gap voltage, not the dynamic vibration signal. Thus, a thrust monitor must use a different NOT OK strategy for detecting and annunciating transducer failures.

[**Editor's Note**: More information on this topic is available in the First Quarter 2001 issue of ORBIT in the article "Voting Thrust Measurements with Other Parameters."]

These "sensor OK" strategy considerations can also affect seismic measurements, particularly for machinery in which impulse-type impact events can occur. Reciprocating compressors are a prime example since extremely high impacts and vibration can occur during a catastrophic failure. These impacts can be so large that the transducer's operating range is exceeded, which will cause a monitor to enter a "NOT OK" condition. A NOT OK condition can suppress normal alarming functions, depending on how the monitor has been configured. Thus, a legitimate machinery failure alarm or shutdown could be suppressed as well. Clearly, this is undesirable.

The 3500/70M Recip Impulse/Velocity Monitor has been specifically developed for measuring acceleration and velocity in reciprocating machinery applications, improving your ability to safely monitor impact events on these machines. On this monitor, if the transducer goes outside of its OK range, as may happen during an impulse event, the monitor will annunciate the NOT OK condition, but will continue to issue alert and danger alarms if those setpoints are exceeded. This ensures that alarming and machinery protection functions will not be suppressed, even in the presence of extremely high-amplitude signals that are outside of the transducer's normal operating range.

Apart from the 3500/70M, many other Bently Nevada monitors are used to measure velocity or acceleration. These other monitors contain an option called "Timed OK/Channel Defeat" that can be either enabled or disabled. When enabled, the monitor will not generate Alert or Danger alarms while in a NOT OK condition. Further, when returning from a NOT OK condition, the monitor must continually be in an OK condition for approximately 30 seconds before alarms will again be enabled. This feature is designed to detect intermittent faults, such as loose wires, that cause an input to fluctuate between OK and NOT OK conditions every few seconds. It prevents spurious alarms by keeping the monitor in a NOT OK condition until a continuously OK signal has been present for a preset time.

Customers using products other than the 3500/70M to make seismic measurements on reciprocating machinery are advised to carefully review their application and their monitor configuration settings to prevent the situation described above. It is **strongly recommended** that if you are using a different Bently Nevada monitor (such as a 3300/25, 3300/26, 3300/55, 3500/42, or 3500/42M) to alarm on high velocity or acceleration conditions on a reciprocating machine, you should disable the Timed

OK/Channel Defeat option. Many of these monitors are shipped from the factory with the Timed OK/Channel Defeat option enabled. While this is a reasonable default for most rotating machinery measurements, it is not suitable for reciprocating machinery. To prevent inadvertent alarm suppression when measuring acceleration or velocity on a reciprocating machine, the 3500/70M cannot be configured to enable the Timed OK/Channel Defeat option. It also contains additional functionality specific to reciprocating machinery (see our sidebar article below), and for these reasons is recommended for all seismic vibration applications involving reciprocating machinery.

If you have questions regarding these recommendations, and the general use of Timed OK/Channel Defeat functionality, please contact your nearest sales engineer, return the reader service card in this issue of ORBIT, or send an e-mail to orbit@ge.com.

3500/70M RECIP IMPULSE/VELOCITY MONITOR

The 3500/70M is recommended for all seismic vibration measurements on reciprocating compressors, rather than a general-purpose velocity or acceleration monitor such as the 3500/42M. In addition to the special NOT OK functionality described in our companion "Recip Tips" article at left, the 3500/70M monitor provides other recip-specific capabilities and has recently been enhanced to provide even more functionality. These enhancements include the following:

- **Crank Angle Alarm Banding** – Because acceleration levels vary widely within a compressor stroke and are typically larger when valves open and close, the ability to establish acceleration alarm levels as a function of crank angle is highly useful. The 3500/70M allows up to 6 separate crank angle "bands" to be defined, each with its own Alert and Danger alarms.
- **Recip Acceleration and Impulse Acceleration Channel Types** – Channels can now be configured for "Recip Accleration" or "Impulse Acceleration." Recip acceleration provides conventional alarming; impulse acceleration provides crank angle banded alarms.
- **Signal Integration** – "Recip Acceleration" channels can now be configured to integrate the signal, providing a derived velocity measurement.
- **Multiple Waveform Types and Improved Filtering Options** – The 3500/70M can now return several types of waveforms to System 1® software, each with different filtering characteristics, allowing improved diagnostics for separating acoustic conditions associated with gas flow from mechanical conditions associated with throw and distance piece resonance.
- **Crank Angle Triggering** – The 3500/70M can now capture asynchronous waveforms beginning at a user-defined crank angle and continue data capture for a specific crank angle duration, allowing users to "zoom" into a particular region of the waveform corresponding to crank angle. It also allows more coherent spectral information for diagnosing high-frequency signal content and permits correlation of impulses with other machine events, such as rod reversal, valve opening, or valve closure.

learn more online at
http://www.gepower.com/o&c/recip

Condition Monitoring Pays Off for Finnish Pulp & Paper Mill

How UPM Wisaforest Uses System 1® Software for Improved Asset Management

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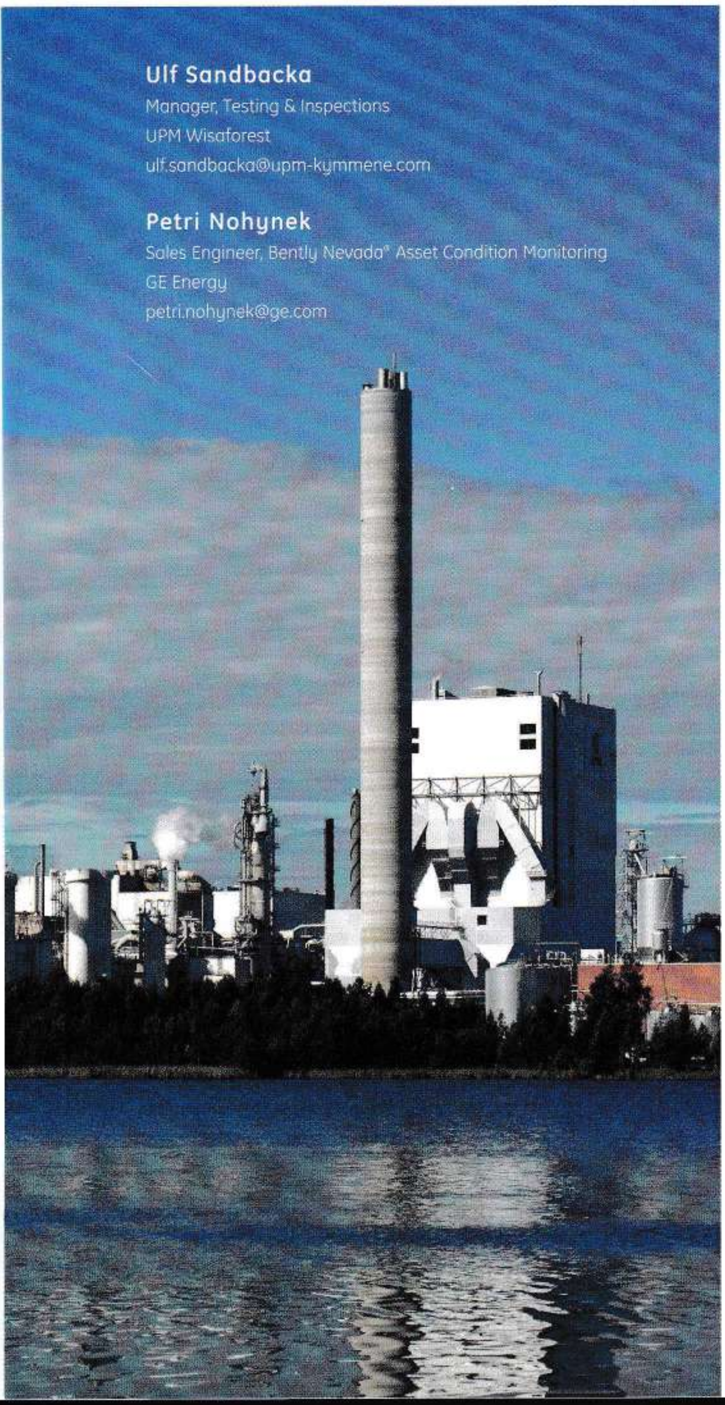


The new recovery island at UPM-Kymmene's Wisaforest pulp and paper mill in Pietarsaari, Finland. The result of the WISA 800 REC project, the new unit boosted the mill's pulp output to 800,000 ADt/a while decreasing environmental discharge to best-available-technology levels.

Introduction

This article explores the use of System 1® software in conjunction with Trendmaster® Pro data acquisition hardware at a pulp and paper mill in Finland. Applied to nearly 50 discrete pieces of process machinery throughout the mill, the system has only been in operation since April 2004, yet has already been instrumental in identifying and solving more than ten separate machinery problems. An overview of the facility and the online condition monitoring system is presented, along with five case histories illustrating how equipment malfunctions are being identified and resolved.

Background

UPM-Kymmene's Wisaforest facility is a pulp and paper mill situated on the Gulf of Bothnia's coast in Pietarsaari, Finland. The pulp mill was originally constructed in 1935 and was designed around a sulfite process. The plant was switched to a kraft process during a 1962 rebuild, and then in 1976 underwent major upgrades to the hardwood and softwood pulp lines. Production capacity today is 800,000 Air Dried tons per annum (ADt/a) of pulp and 180,000 ADt/a of kraft and sack papers. The mill generates its own power and is entirely self-sufficient in this respect. It utilizes two production lines throughout, with exception of the new recovery island (WISA 800 REC project), discussed next.

WISA 800 REC Project

The WISA 800 REC (RECovery) project had several goals, summarized in Table 1. The project entailed a single line to replace the mill's two previous recovery lines, which were in bad mechanical condition and date from 1962 and 1975-1976, respectively. This new line is sized to meet the mill's pulp production capacity of 800,000 ADt/a. To achieve this capacity, the two existing fibre lines were improved, resulting in better strength properties of the pulp. Additionally, a new sawdust cooking line was added, providing more flexibility in the raw material base by allowing the use of sawdust as feedstock for selected pulp qualities, rather than burning it as had been done previously. This delivers both environmental advantages (fewer emissions) and process advantages by allowing the mill to draw from a larger pool of locally available sources for pulp feedstock.

In addition to the goals for the WISA 800 REC project, the scope was likewise very extensive as summarized in Table 2. The main equipment suppliers for the recovery island were Andritz Corporation for much of the process equipment, Siemens AG for the main turbo-generator, and Metso Automation for the process control system. For the condition monitoring (CM) system, GE Energy was chosen to supply their Bently Nevada® solutions consisting of System 1 software, Trendmaster Pro hardware, and a 3500 monitoring system. Startup of the new recovery departments occurred on-schedule in April 2004.

Table 1 –

GOALS OF WISA 800 REC PROJECT

- Become one of the most cost-efficient pulp mills in Europe
- Increase pulp capacity to 800,000 ADt/a
- Decrease the environmental discharge levels to best-available-technology
- Replace old and worn out equipment.
- Expand raw material options by using sawdust for pulp production (instead of burning it)

Table 2 –

SCOPE OF WISA 800 REC PROJECT

- **Service Module B**
  office building, control room, maintenance rooms
- **Evaporation Plant**
  7+ stages, (1,050 tons H_2O per hour, 82 - 85 % dry solids)
- **Recovery Boiler**
  steam production 180 – 205 kg/s, 92 – 102 bar, 492 – 505 °C, 4,450 tons dry solids per day
- **Back-Pressure Turbine-Generator***
  143 MW
- **Causticising Plant**
  10,000 m^3/day white liquor
- **Lime Kiln**
  750 tons of CaO per day
- **Steam Condensate Treatment**
  200 litres per second
- **Tall Oil Plant**
  192 tons per day

* According to Siemens AG, this is the world's largest back-pressure turbine generator used in the pulp & paper industry.

Table 3 –

CONDITION MONITORING SYSTEM SUMMARY

Department	Number of Machines	Machine Types	Monitoring System
Evaporation	6	pumps, mixers, fan	Trendmaster Pro
Recausticizing	18	pumps, compressors, mixers, filters, fan	Trendmaster Pro
Recovery Boiler	14	pumps, mixers, fans	Trendmaster Pro
Lime Kiln	11	pumps, mixers, filters, fans, lime kiln, supporting rolls and drives	Trendmaster Pro
Turbo-Generator	1	143 MW back-pressure steam turbine	3500 Series

The Lime Kiln rotates at extremely slow speeds (~10 rpm) on supporting rolls that use fluid-film bearings.

The Condition Monitoring System

Employees working with the WISA 800 REC project defined the scope of the CM system. Production line leaders, assisted by the maintenance department, first defined the machines that were most critical for the plant production. Once the machines to be addressed were determined, the appropriate monitoring technology was then identified. The results of the plant's evaluation are summarized in Table 3.

Large, high-speed turbomachinery generally warrants a conventional rack-based continuous monitoring system, and the plant chose Bently Nevada proximity probes coupled with the 3500 Series Machinery Protection System. With exception of the lime kiln, as discussed below, all other machinery uses rolling element bearings and is more appropriately addressed by a monitoring system using a scanning architecture. Accelerometers (Bently Nevada 200350) were deemed appropriate for these machines, linked to the Bently Nevada Trendmaster Pro system. Both the 3500 and Trendmaster hardware were equipped with System 1 software connectivity, allowing these systems to be linked into a common diagnostic platform.

[Editor's Note: For additional information on the classification of machinery criticality and selection of corresponding monitoring technology, please refer to the article *Trendmaster Goes Pro* in the Second Quarter 2004 issue of ORBIT, pp 30-47.**]**

The massive bearings on the lime kiln supporting rolls are fluid-film type and the rotational speed is very low (approximately 10 rpm). Initially, the plant determined that these 16 bearings would use X-Y proximity probes for vibration monitoring. However, this decision was made late in the project, after the kiln had been supplied and installed, making transducer retrofits considerably more difficult than if this had been specified to the OEM for factory installation of probes. Consequently, it was necessary to equip these bearings with accelerometer transducers. It was recognized that this was not an ideal application, but project constraints dictated this compromise. In order to provide rpm and phase reference information, Keyphasor® transducers were installed observing a suitable shaft discontinuity on each clutch.

Wisaforest selected three experienced CM technicians to be the primary users for the condition monitoring system, and these individuals have full configuration privileges for the entire system. In addition, there are five display licenses at the plant, one permitting a display client in the control room, and four for various maintenance and operations personnel elsewhere in the plant.

Project Execution

The project startup meeting was held on 3 December 2003. One of the first items that needed to be defined was the total number of measurement points. This number would determine how many Trendmaster Pro Dynamic Scanning Modules (DSMs) would be required, as each DSM can handle multiple transducer inputs. The number of DSMs required represents a balance between wiring costs, DSM costs, and scanning times. For this reason, each application must be evaluated on a case-by-case basis. While a single, centrally located DSM can handle hundreds of measurement points, the wiring costs can be quite high. In addition, the more points assigned to a single DSM, the slower the scanning time will be as it must multiplex among all its inputs. The most economical solution is often to install multiple DSMs, where a cluster of measurement points occur, and then to link the DSMs using conventional wired or wireless Ethernet. Due to the small bandwidth requirements, this can often be achieved over existing plant networks rather than requiring a dedicated CM network.

For the WISA 800 REC project, it was determined that 10 DSMs would be the optimal number, reflecting the appropriate balance of wiring costs, hardware costs, and scanning times. Next, the locations for these DSMs were determined. This will vary from one application to the next based on wiring topology, availability of power and network connections, and other factors. The final step was to determine project installation scope. It was decided that Wisaforest would be responsible for providing all Local Area Network (LAN) connections along with locally available power at each DSM location. The GE Energy team would be responsible for installing all sensors, cabling, cabling shields, junction boxes, and DSMs. In addition, they would be responsible for the installation and configuration of the System 1 software along with integration to the plant's process control system.

When field hardware installation was approximately 20% complete, System 1 software installation commenced. A significant element of the overall project was to configure the software with appropriate monitoring parameters such as alarm settings, frequency bands, point labeling, and many other details. The machines in the facility vary from one another in many ways including operating speed (1 – 3000 rpm), drive mechanism (direct, belt, and gear), and operating mode (constant speed, variable speed, constant load, variable load). This entails a high level of cooperation between numerous suppliers, plant personnel, and GE Energy to determine and document the correct values for all settings, and then enter these values into the software's configuration screens.

In addition to the items already noted, a project of this magnitude entails many other details, a few of which are summarized below:

- Server model and its installation location
- Determination of LAN type (copper or fiber) and connections thereto
- Labeling of cables and sensors
- System wiring topology
- Interconnection of DSM hardware and 3500 System to System 1
- Ongoing dialog with machinery OEMs
- External computer support

- Coordination of machine test schedules with readiness of CM system, allowing analysis of start-up data
- Integration with process control system and appropriate data types for display to operators

The last bullet in the above list merits additional discussion. Originally, the project scope did not include an interface between the process control system and System 1 software. However, as the usage scenarios of the CM system were further defined, the ability for operators to view basic condition information using their process control system was deemed important, while still providing in-depth diagnostic capabilities for rotating machinery engineers via System 1 software's user interface. This resulted in two primary user interfaces: one for operators, and one for machinery specialists. A bi-directional OPC link was used for this interface, allowing the plant to not only import direct amplitudes and alarms from the System 1 platform into the DCS, but also to export numerous process variables from the DCS into the System 1 database.

[**Editor's Note:** You can read more about the usefulness of process data correlation in a CM system and the importance of making select CM data viewable in the plant control system in the article *Best Practices for Asset Condition Management* in the Third Quarter 2001 issue of ORBIT, pp. 46-47.]

Taking the New Recovery Unit into Operation

As anyone who has been involved in a plant startup can attest, one of the most crucial times for the CM system is when machines are tested and brought online for the first time. Problems that may not have been apparent at the factory may surface, or the installation of the machine may have introduced problems (e.g., alignment, piping strain, lube contamination, etc.). Consequently, a very important aspect of the project was to ensure that the CM system was configured and ready for use as each machine was started up.

The first test runs for the new recovery unit started on 12 February 2004. Through careful advance planning and schedule coordination, the CM system was ready to begin monitoring these machines. As other machines were subsequently brought online, the System 1 configuration and commissioning were coordinated to coincide with their start-up dates as well.

By 1 April 2004, when the new recovery unit officially began full-time operation, all measurement points had already been collecting data for several weeks. Subsequently, the team turned its attention to "fine tuning" alarm levels and other system configuration settings, now that actual data was available from the operating machines. During these adjustments, no machine failures could be allowed, and faulty operating conditions needed to remain visible. Wisaforest and GE Energy worked collaboratively to successfully accomplish these objectives in a timely fashion.

As previously mentioned, although the plant started full-time operation on 1 April, machinery testing commenced several weeks prior to that date. During this start-up phase, a number of machinery problems were identified by the CM system, allowing proactive intervention and remedy – even before the entire plant went "live." This early payback of the system and its usefulness during startup activities had been a high priority for the Wisaforest project team and was part of the justification for installing the system in the first place. All participants were extremely pleased that the system demonstrated its value so early in the project. After full-time operation commenced, the system continued to deliver value by logging many other machinery "saves." Several of these saves are summarized next.

Case History #1

Problem: **Bearing Lubrication**

Machine: **Secondary Air Fan**

Unit: **Recovery Boiler**

The secondary air fan is a 600 kW direct-driven overhung fan that is critical for the recovery boiler operation. Shortly after startup, abnormal changes in trends of the high-frequency data from the inboard bearing accelerometer were noted. Figure 1 is taken directly from the System 1 software, showing a 2-month trend of high-frequency data from the accelerometers on the inboard and outboard bearings. The elevated levels on the inboard bearing (blue) compared to the outboard bearing (orange) are readily apparent.

Access platform for Secondary Air Fan.

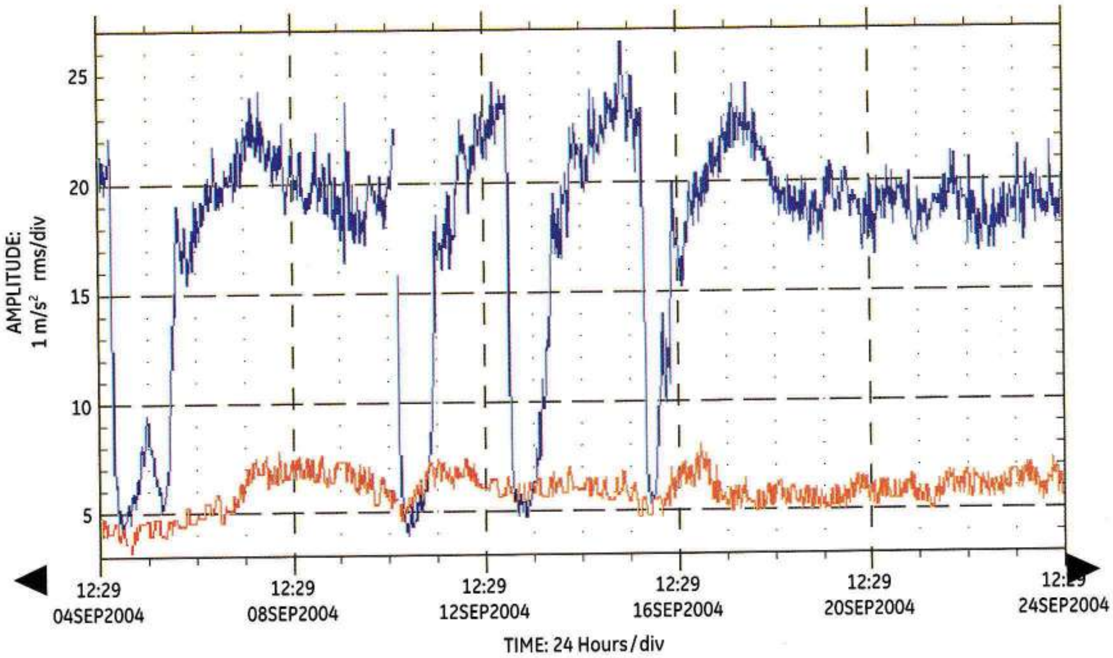


Figure 1 – Trend of high-frequency vibration amplitude from inboard bearing (blue) and outboard bearing (orange) showing elevated vibration levels at inboard bearing. The "dips" show the intermittent operation of the lubrication system, allowing the inboard bearing vibration to temporarily decrease to normal levels.

Spectral analysis suggested that the bearing's outer ring was wearing prematurely, and the root cause was ultimately traced to problems with the bearing lubrication system. The prominent "dips" in the trend plot correspond to intermittent operation of the lubrication system, showing a marked decrease in vibration for the inboard bearing when lubrication was flowing properly.

Even though root cause was identified, implementing the changes to the lubrication system was a lengthy process, and the machine was required to operate in the interim. Thus, although the bearing had to be replaced twice during the first six months, the CM system proved very useful in scheduling these replacements, allowing the plant to monitor bearing degradation closely and intervene at the right times, before catastrophic bearing failure and collateral machine damage occurred. Also, these outages could be planned, allowing the bearing change-outs to be performed when impact to production was minimized.

> **THE CM SYSTEM PROVED VERY USEFUL IN SCHEDULING THESE REPLACEMENTS, ALLOWING THE PLANT TO MONITOR BEARING DEGRADATION CLOSELY AND INTERVENE AT THE RIGHT TIMES.**

Case History #2

Problem: Resonance
Machine: Lime Kiln Driver
Unit: Lime Kiln

The lime kiln is a large machine, approximately 4.7 meters (15.4 feet) in diameter and 135 meters (443 feet) long, with extremely slow rotational speeds (as low as 5 rpm). Two drivers provide rotational power, and, depending on production conditions, the kiln must run at different operating speeds. When the kiln ran at higher speeds, higher vibration levels were noted, occurring predominately at 2X. This led plant personnel to initially conclude it was an alignment problem, but realignment of the drivers did not correct the situation and vibration levels remained elevated. A re-examination of the vibration data was conducted, this time by looking at phase and rpm data in addition to amplitude and frequency (Figure 2 and Table 4).

One of two drives for the plant's massive Lime Kiln.

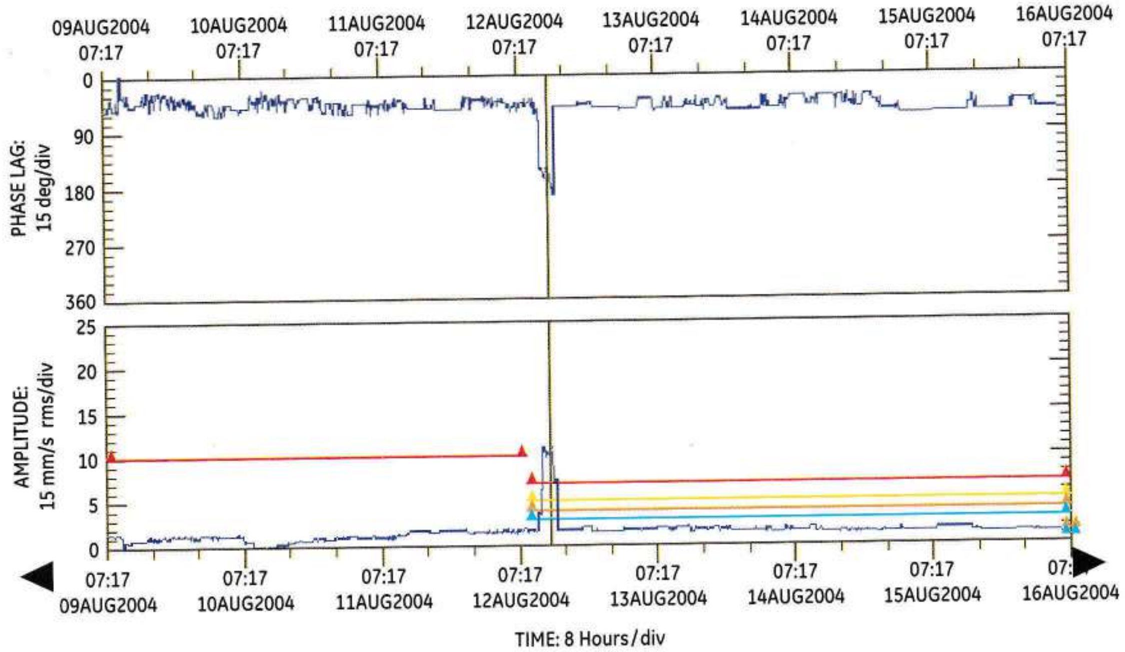


Figure 2 – **Amplitude/Phase/Time (APHT) plot of vibration data from lime kiln drive rollers with motor speed varying between 991 rpm and 1083 rpm.**

Table 4 –

SUMMARY OF 2X AMPLITUDE AND PHASE DATA WITH RPM AND DATE/TIME STAMPS

Date/Time	Speed (rpm)	Amplitude (mm/s rms)	Phase Lag (deg)
12 Aug 2004 10:29:30	991	1.50	51
12 Aug 2004 10:32:23	1030	3.72	64
12 Aug 2004 10:46:47	1031	3.76	62
12 Aug 2004 10:49:40	1033	3.81	60
12 Aug 2004 11:06:58	1050	6.30	74
12 Aug 2004 12:59:24	1066	10.10	160
12 Aug 2004 13:05:10	1068	10.88	166
12 Aug 2004 13:13:49	1083	6.94	184
12 Aug 2004 13:54:11	996	1.82	52

Amplitude reaches a maximum and phase undergoes a 90-degree shift (relative to phase at 991 rpm) at approximately 1070 rpm. Vibration occurs at twice running (excitation) speed or 1070 x 2 = 2140 cpm (36 Hz).

THE PRIME MINISTER OF FINLAND, PUSHED THE "MAXIMUM OPERATION" BUTTON.

Figure 2 is an Amplitude/Phase/Time (APHT) plot where the horizontal axis is time. It has characteristics very similar to a Bode plot, whose horizontal axis is machine speed rather than time; namely, if the machine speed is changing markedly with time, an APHT plot can show a resonance response, just as a Bode plot. The classic features of resonance are two-fold: First, the filtered (1X, 2X, etc.) amplitude will increase to a maximum at a rotational speed that excites the resonance, and then will decrease as the machine speed goes above this frequency. Second, the phase lag will undergo a 180-degree shift, generally passing through approximately 90 degrees at the point of resonance.

While Figure 2 does not label each individual data point with its corresponding rpm, System 1 software is capable of providing this information as a tabular output. The points clustered between 10AM and 2PM on 12 August 2004 showed the most dramatic shifts in amplitude and phase, and coincided with a change on the kiln from low-speed operation to high-speed operation and back again. A tabular output of the data points in Figure 2 was generated, and a subset of this data is summarized in Table 4, clearly showing the correlation between amplitude/phase changes and running speed, and helping to confirm a structural resonance at approximately 36 Hz.

During subsequent maintenance on the unit, the supports for the drivers were stiffened and strengthened, raising the resonant frequency of the structure and eliminating the vibration problems.

[**Editor's Note:** Resonance is a well-understood phenomenon in machines and structures, and operation of rotating machinery at a running speed that coincides with a resonance is never done deliberately. Sustained operation at a structural resonance frequency can result in very high vibration amplitudes, fatiguing connections and components, and prematurely wearing the entire machine. However, as this case history shows, it can be equally damaging to operate a machine at a speed that coincides with one-half of the resonant frequency – allowing the normally small 2X vibrations generated by the machine to excite this resonance. Resolution of this problem was instrumental in ensuring the kiln could achieve expected maintenance intervals and maximum useful life.]

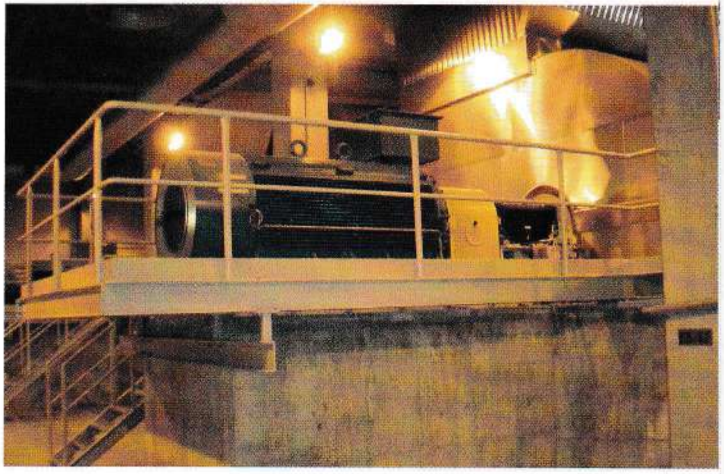
Case History #3

Problem: Bearing Failure

Machine: Exhaust Gas Fan

Unit: Recovery Boiler

The official dedication for the WISA 800 production unit took place on 24 August 2004. The Prime Minister of Finland was in attendance, and, as part of the ceremonies, pushed the "maximum operation" button, allowing the recovery boiler to reach world-record production capacity for a time. This mode of operation required the exhaust gas fans to run faster, and the CM group began to notice an increase in 2X vibration amplitudes on fan #3, as evident in the APHT plot of Figure 3.



Access platform for Exhaust Gas Fan #3.

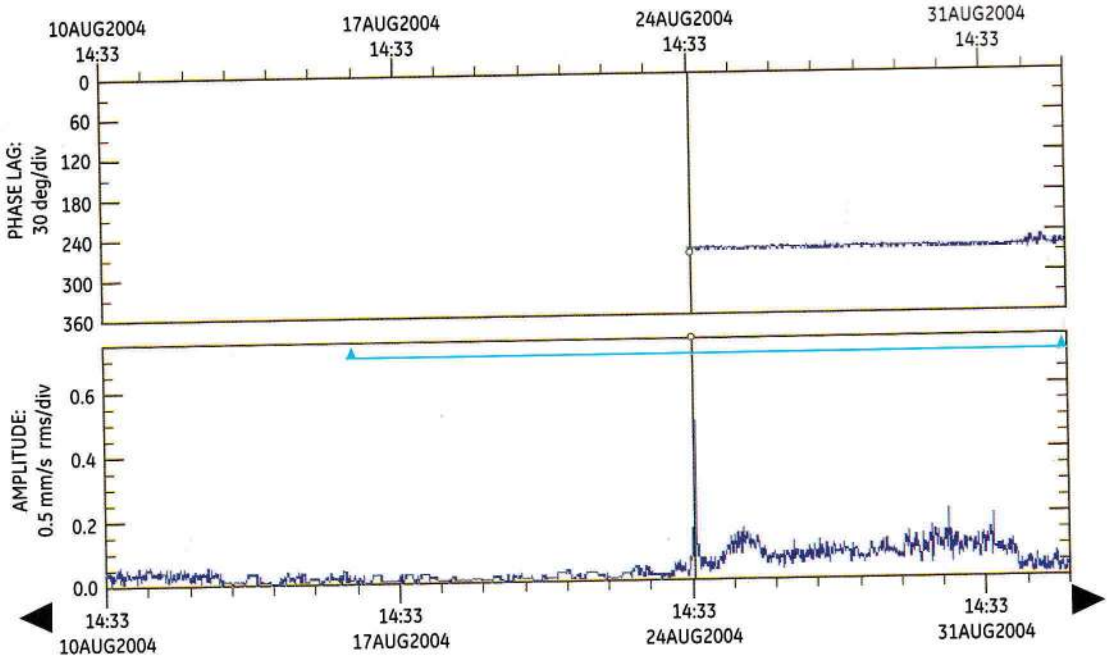


Figure 3 – Amplitude/Phase/Time (APHT) plot of 2X vibration data from outboard bearing accelerometer on Exhaust Gas Fan #3. Note that amplitudes prior to the cursor location on the plot were so low that phase readings would not trigger consistently; as vibration amplitudes increased, phase readings stabilized.

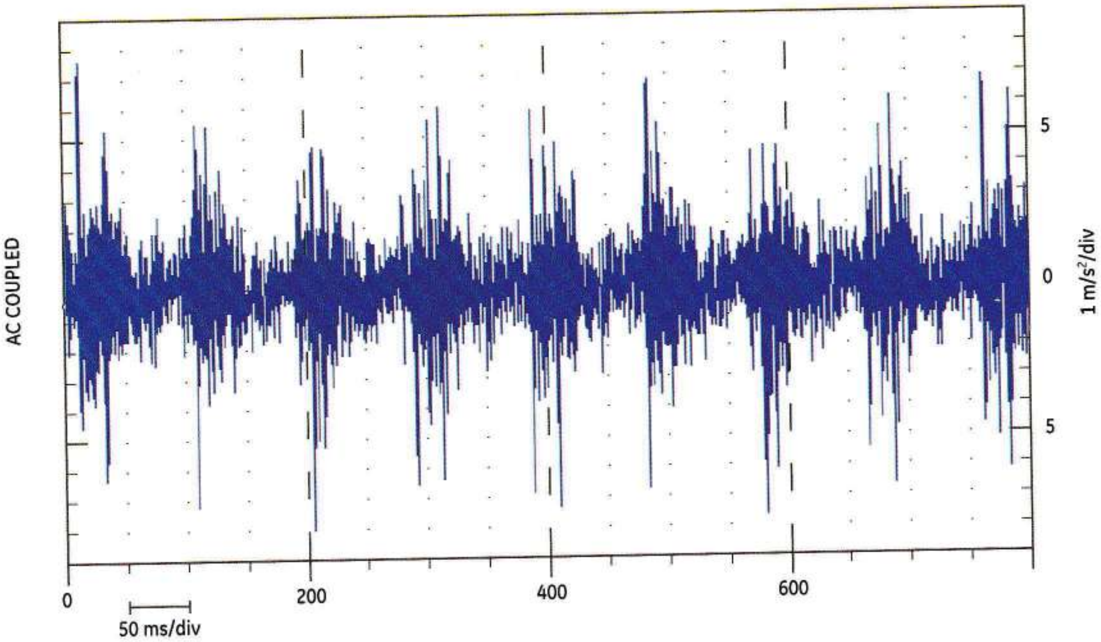


Figure 4 – Unfiltered timebase plot from outboard bearing accelerometer on Exhaust Gas Fan #3. Note characteristic "ringing" phenomena as inner race defect is impacted by rolling elements.

Closer examination revealed that the outboard bearing of fan #3 had likely sustained a crack in the inner ring, which can be noted in the timebase of Figure 4. The characteristic "ringing" phenomenon observable in the timebase occurs at the inner ring defect frequency as the cracked inner ring repetitively rotates through the load zone and the rolling elements contact it with greatest force.

Subsequent to that event, the bearing has been monitored closely, allowing operations to continue without replacing the bearing. The defect does not appear to be progressing and is not serious enough to necessitate a bearing replacement until a more convenient time can be scheduled.

[Editor's Note: It is not clear whether an invoice for a new bearing will be sent to the Finnish Prime Minister's office.**]**

FOR WISAFOREST, THE ECONOMIC BENEFITS HAVE SUBSTANTIALLY EXCEEDED EXPECTATIONS... RESULTING IN AN ESTIMATED PAYBACK TIME FOR THEIR INVESTMENT OF JUST 8 WEEKS.

Case History #4

Problem: Faulty Coupling
Machine: White Liquor Pump
Unit: Recausticizing

A typical pulp mill has hundreds of pumps. At Wisaforest, 15 of these were deemed suitably important to connect to the CM system. In late May 2004, as shown in Figure 5, increased vibration levels were noted on the motor driving the white liquor pump. Further analysis revealed that the rubber element in the coupling had deteriorated, allowing metal-to-metal impacting. The coupling was subsequently repaired and vibration levels returned to normal.

White Liquor Pump showing motor and coupling guard.

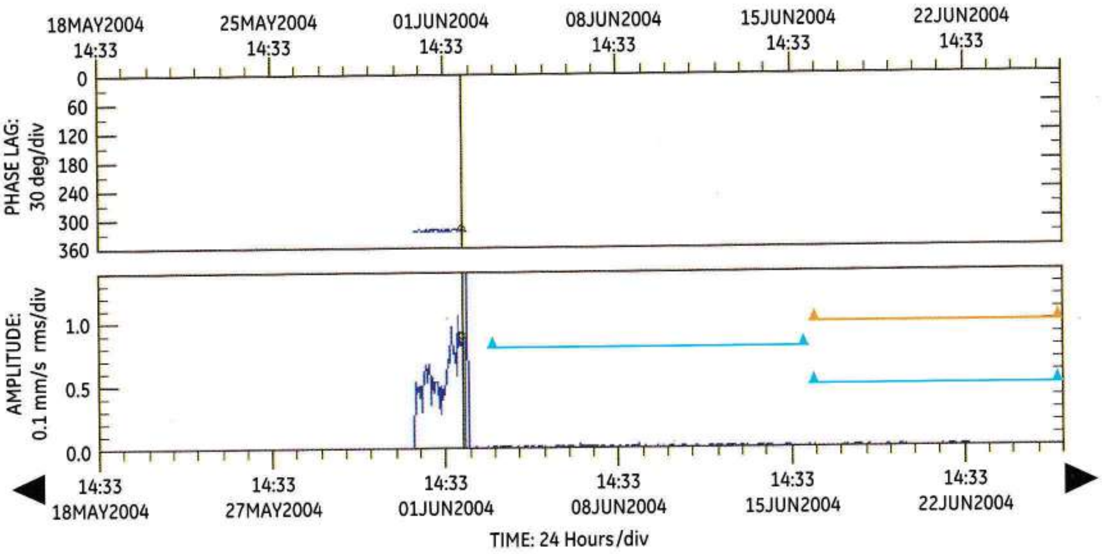


Figure 5 – **Amplitude/Phase/Time plot of 2X data from accelerometer on motor driving the white liquor pump. Note abrupt increase in vibration amplitude beginning on 30 May 2004. A deteriorated coupling insert was found to be the cause, and was replaced on 1 June 2004, returning vibration levels to normal values.**

Case History #5

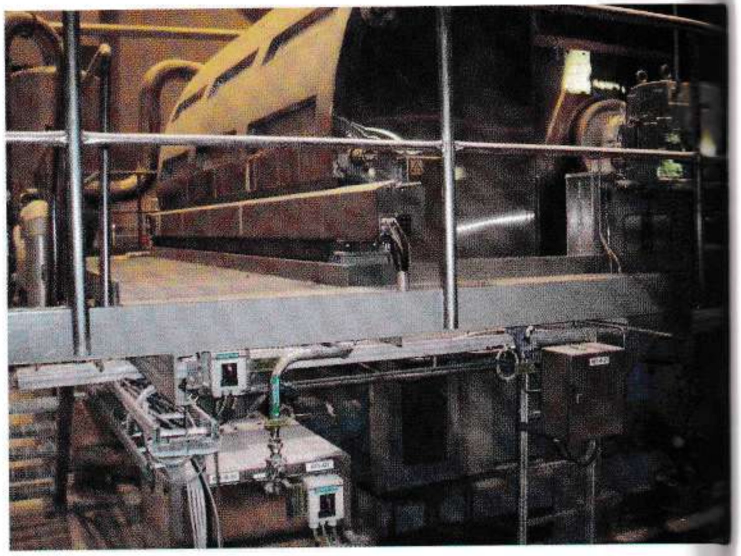
Problem: Bearing Deterioration

Machine: Mixer Adjacent to Rotary Filter

Unit: Recausticizing

Rotary filters are one of the most difficult machines to monitor since their rotational speed can be extremely low – as little as 0.5 rpm. The bearings are fitted with accelerometers and acceleration enveloping is one of the signal processing techniques used to help identify degradation and other anomalies.

In early September 2004, the CM group began to notice increased vibration levels on the filter's inboard bearing, observable in both the enveloped amplitude and the high-frequency amplitude trends (Figure 6).



The rotary filter. Accelerometers were mounted on the filter bearings and the gearbox (green, upper right); however, the problem was traced to an unmonitored mixer underneath the filter (concealed in lower left corner of photo).

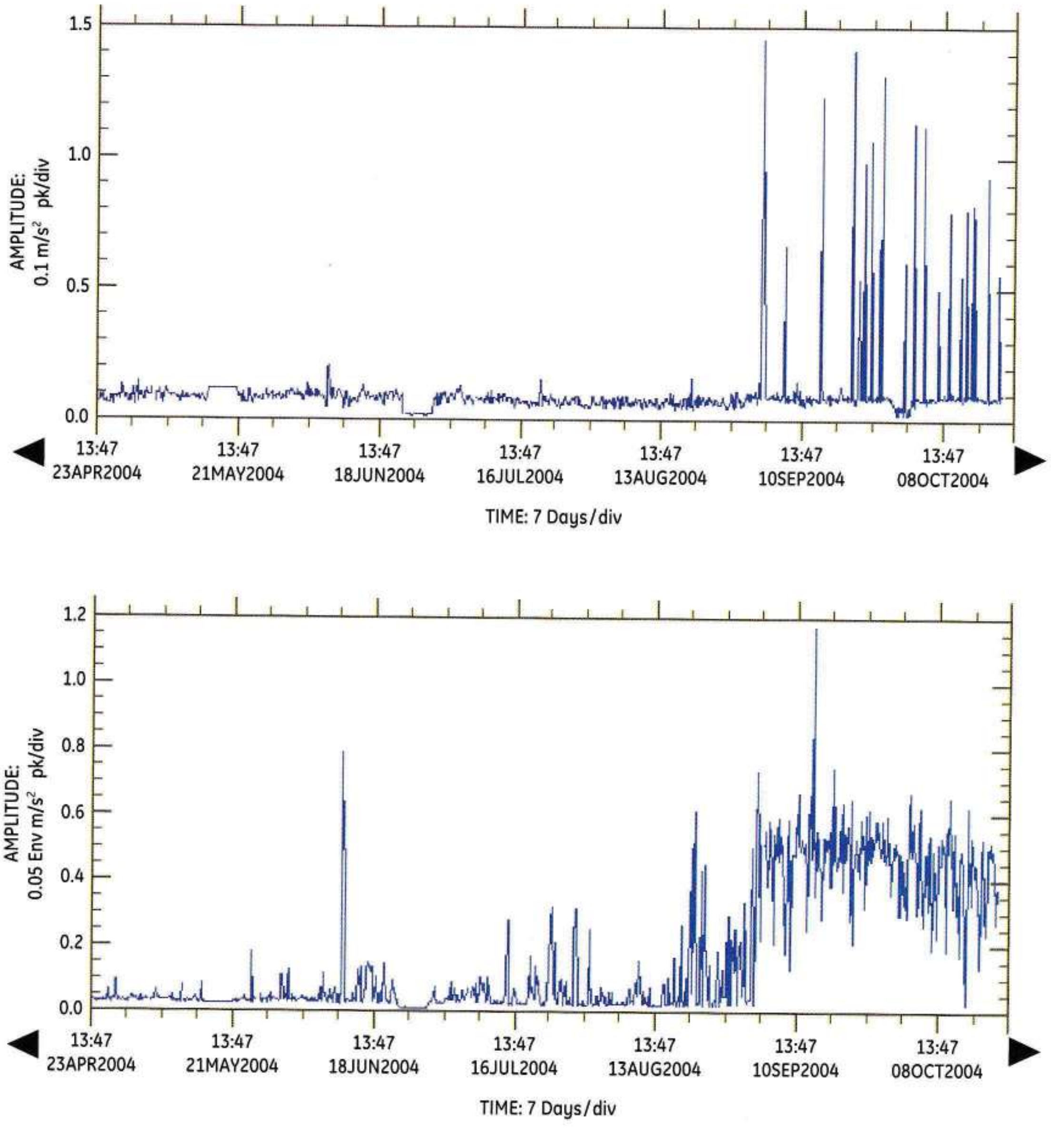


Figure 6 – Amplitude trends from rotary filter bearing accelerometer showing high-frequency acceleration (top) and enveloped acceleration (bottom). Note increased amplitudes in both signals beginning on approximately 3 September 2004.

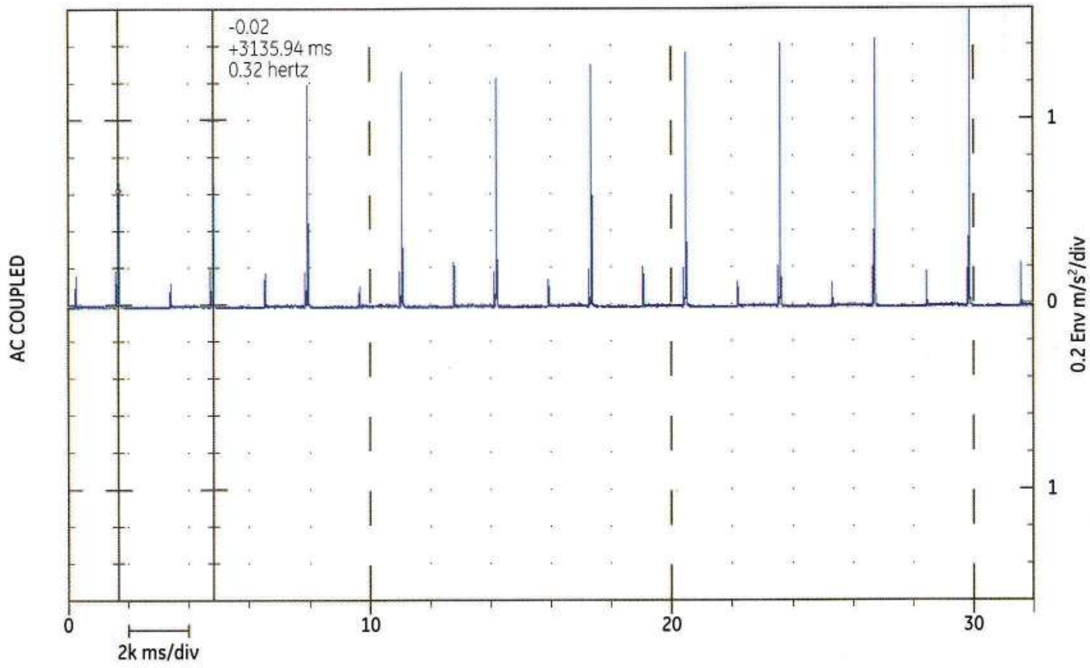


Figure 7 – **Timebase plot of enveloped acceleration showing clear evidence of impacting. Spectral analysis yielded frequencies that did not coincide with bearings used on the rotary filter, leading the plant to look for faults elsewhere.**

The enveloped acceleration timebase (Figure 7) showed very clear evidence of periodic impacting, but examination of the spectral components did not yield any frequencies corresponding to the bearing geometries or rotative speeds of the filter or its gearbox. A visual examination of the filter gave the reason: it was not the filter at all, but rather a separate mixer, located below the filter, with a damaged bearing. Although the mixer was a *totally unmonitored machine*, the impact vibrations occurring from its faulty bearing were being mechanically coupled into the accelerometer on the filter bearing, located nearby. The root cause was found to be broken lubrication piping feeding the mixer bearing, which was subsequently repaired. However, the bearing had been irreparably damaged and had to be replaced. This case history is particularly noteworthy in that it demonstrated the sensitivity of the monitoring system to detect changes in even unmonitored machinery. While certainly not recommended as a deliberate CM strategy, it was an unexpected – and, as it turned out – valuable fringe benefit.

Payback

While the users of the CM system are very pleased with its diagnostic capabilities, it is important that we are able to continually justify to plant management and operations the value of condition monitoring and diagnostics in general. For Wisaforest, this translates to economic benefits, and those benefits have substantially exceeded expectations. Several of the machines highlighted in these case histories have a critical role: they will cause a complete stop in plant production if they do not run,

STRONG CREDIBILITY HAS BEEN ESTABLISHED WITH MANAGEMENT REGARDING THE VALUE OF CONDITION MONITORING.

representing substantial lost production costs. Plant personnel have avoided several total outages through use of the system, resulting in an estimated payback time for their investment of just 8 weeks.

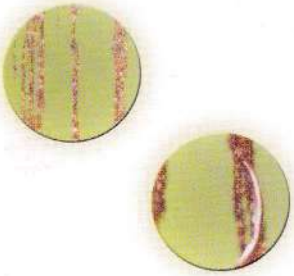
Both the maintenance and production departments now view the system as far more than just a tool for strengthening preventive maintenance capabilities – it is viewed as a tool for increasing the mill productivity. Strong credibility has been established with management regarding the value of condition monitoring and its role in ensuring plant uptime, leading the plant to consider expanding the system to additional equipment.

Summary

Wisaforest is achieving ongoing success with their CM system for several reasons:

- Proven, quality technology from a knowledgeable supplier was chosen as the basis for the plant's CM program.
- The plant enlisted the assistance of the supplier to help install and implement the technology correctly.
- Adequate transducers were installed where feasible, including speed/phase, rather than just vibration, allowing confirmation of faults that would have been difficult or impossible to isolate when limited to only amplitude and frequency data (e.g., case history #2).
- Start-up activities were coordinated to include the condition monitoring system as "must have" capabilities before a machine was brought online.
- Plant management made certain that everyone understood the CM program's goals and objectives, and that there was buy-in from all parties. This helped ensure that the system would be used proactively and consistently.
- The CM system was integrated with the process control system, allowing operators to have early visibility to developing conditions, and allowing process data to be available for correlation with vibration data when performing in-depth diagnostics.
- Results were documented, allowing the users to quantify the system's value to management and other stakeholders in the plant.

Consequently, the WISA 800 REC project has led to not only a world-class facility, but world-class asset management practices and world-class results.



Oil Analysis 101

Part 1 of 2

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What is oil analysis and why should you do it?

When you go for a medical checkup, a blood sample is usually taken and the results help the doctor determine if there are any problems with vital organs. Similarly, because oil is the lifeblood of machinery, analysis can help detect a developing problem in the oil-wetted path of a machine (Table 1).

Oil analysis has been used for at least fifty years for measuring the wear condition of machinery. The railroad industry discovered that the metals found in a sample of used oil revealed the condition of the wearing parts in the diesel engine. Likewise, oil analysis has been a mainstay in the military for monitoring the wear condition of aircraft jet engines and gearboxes. Heavy industry, however, was slower to appreciate the valuable insights that only oil analysis could bring to the predictive maintenance field.

[**Editor's Note:** This is part 1 of a 2-part article designed to answer basic questions about oil analysis for those unfamiliar with the technology or its benefits. In this installment, the author describes the three facets of oil analysis and the various laboratory analytical methods used. In a future issue of ORBIT, part 2 will explain how oil analysis complements vibration analysis in an overall program for ensuring machinery health, and how to establish a successful oil analysis program in your plant.]

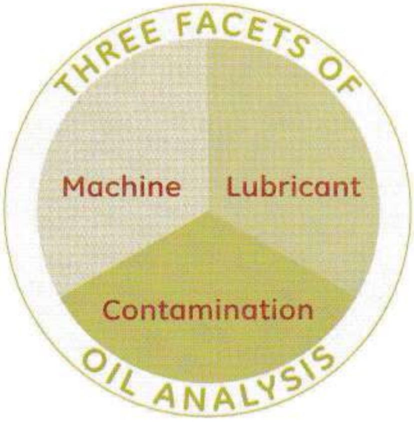
**CRITICAL FLUID MONITORING –
A COMPARISON OF FLUIDS ANALYSIS QUALITY PARAMETER**

TABLE 1 –

Quality Parameters	Blood Analysis	Oil Analysis
Fluid Condition	Serum Biochemistry Tests Full Blood Count Tests	Spectrochemical Analysis (Additives), Viscosity, Oxidation, Acid/Base Number, Moisture Tests
Contamination Condition	Cholesterol & Lipids Tests	Oxidation, Nitration, Sulfation Viscosity, Solids/Sludge Content, Particle Counts
Component Condition	Thyroid Function Tests	Spectrochemical Analysis (Wear Metals), Wear Debris Analysis
	Liver Function Tests	Particle Counting, Acidity Tests

Today, oil analysis is beginning to take its place alongside vibration monitoring as an indispensable and valuable element of industrial predictive maintenance. In this tutorial we will:

- Examine the three facets of oil analysis.
- Explore how oil analysis complements vibration monitoring.
- Discuss the steps for establishing an oil analysis program.
- Provide advice on oil sampling.
- Offer thoughts on using your senses, postmortems, and quality.



The Three Facets of Oil Analysis

There are three dimensions to lubricant analysis:

- **LUBRICANT** – Comparison of the chemicals and physicals of the sample against virgin oil to determine if it remains an adequate lubricant.
- **CONTAMINATION** – Monitor overall particle cleanliness in the oil for purposes of contamination control.
- **MACHINE** – Analyze sample for metal particles to determine condition of oil-wetted (wearing) machinery parts.

Lubricant Condition Monitoring

Determining whether a machine's oil is fit for further service typically requires several tests. Analysis results are quantified by comparison with virgin oil of the same make and type.

There are five main tests that are employed in this analysis process, depending on the application.

1 Viscosity

Viscosity is the single most important physical property of a lubricant and should be checked periodically. An abnormal viscosity value is an excellent indicator of a problem, although pinpointing the root cause can be tricky. Sometimes taking viscosity measurements at two temperatures (usually at 100 °C and 40 °C) is important. This allows for the calculation and reporting of a Viscosity Index (VI), which is an indication of how oil viscosity varies with temperature. This test is usually called for when the machine is required to operate over a wide temperature range.

2 Oxidation

When the oil is oxidized or has become too acidic, it must be replaced and disposed of. There are a number of tests used today that monitor for oxidation or acid. Total Acid Number (TAN), Total Base Number (TBN), Rotary Bomb, pH, and FT-IR are all employed routinely. FT-IR (Fourier Transform InfraRed Spectroscopy) is a relatively new alternative technology that looks at the compounds in the oil and can monitor and trend many of the parameters formerly done by ASTM (American Society for Testing and Materials) testing. An inexpensive screening test, FT-IR is routinely used by many of the more progressive labs for monitoring and trending oxidation, water, glycol, fuel dilution, sulfation, nitration, soot, and certain additives. Additives are chemicals added to oil that are designed to either enhance the good properties of the basestock or suppress the undesirable.

FT-IR Spectrometer

ASTM tests are more expensive and are only performed when it is necessary to corroborate exceptions in a result. For example, if FT-IR indicates high oxidation the lab will then perform the TAN test to confirm. It should be standard practice to have the FT-IR "signature" of the virgin oil already on file in the computer in order to detect the abnormal compounds present. Despite the advantages of FT-IR, certain ASTM tests should be routinely performed on some critical machinery in order to conform to either the manufacturer's requirements or to the user's standards.

3 Water Content

Water is usually an undesirable contaminant in oil and large amounts will lead to lubricant degradation, which accelerates corrosion and the promotion of wear. Water content should always be checked as part of any oil analysis program. Several common methods exist, and each has a different level of sensitivity or detection. The oldest and easiest is The Crackle Test. This simply involves dispensing a drop of oil onto a heated hot plate and, by the amount of "crackling," one can get a qualitative idea of whether the water is greater or less than 1% (10,000 parts per million (ppm)). The water by centrifuge test is regularly employed for quantitative measurement of gross water contamination. Although quick and accurate, it has poor sensitivity at low water levels. Many new lubricants contain additives (surface active agents that emulsify the water to prevent large drops) that can interfere with this analytical method. Another widely used and simple test is the Dean Stark Distillation. This procedure removes water from the sample by means of an azeotrope and the results are accurate down to 0.05% (500 ppm). The Karl Fischer Water (KFW) test is the most commonly specified ASTM test for moisture and has the great advantage of good accuracy at low levels of moisture, down to 10 ppm (0.001%). Its one drawback is that skilled personnel are required to operate it. FT-IR (described earlier) is also a good trending method for water and can report content as low as 1000 ppm (0.1%).

Karl Fisher method of measuring water contamination in oils.

4 Particle Counts

Numerous designs of automatic particle counters (APCs) exist for both lab and field use and include both portable data collectors and online instruments. All of them report the number of particles in various size categories, depending on the cleanliness standard being used. Typical oil cleanliness standards employed are the Society of Automotive Engineers (SAE), the National Aerospace Standard (NAS), or the International Organization for Standardization (ISO). Although these instruments are principally used for monitoring hydraulic or turbine systems, their application has been extended to gearboxes and other plant equipment, thanks to new methods of analysis. Significant increases in particle counts can indicate many problems such as a failed filter, a contaminant entering the system, or a higher wear rate beginning. Subsequent testing is required with APCs for diagnosis of the root cause of higher particle counts.

Particle Counter

CONTAMINATION CONTROL

Sources of Contamination

Solid contamination can be caused by many events. High levels at a particular point in the machine can be used as a signal that something abnormal is occurring.

High contamination levels can be due to a failed filter and can be proven by taking both upstream and downstream samples. This argues in favor of installing sampling points on either side of the filter and monitoring downstream on a regular basis. A high particle count necessitates sampling from both sides to corroborate. An increase in wear rate of the wetted parts in the machine can increase both the particle number and size in the oil. Contamination can also enter the oil system via breather pipe, faulty seals, or failure to replace a protective filler cap. When the oil becomes acidic or highly oxidized, it attacks the metallic components in the oil-wetted path leading to a significant buildup of corrosive sediment. This is by no means an exhaustive list, but highlights common sources of solid contamination in oil.

Oil Replacement and Reclamation

It is axiomatic in machinery maintenance that oil is the lifeblood of machinery and, therefore, must be carefully maintained. One might argue that periodic oil changing is sufficient and that argument held sway for many years. However, today's focus on cost minimization and environmental protection has combined to inspire maintenance managers to replace oil based on its condition rather than the calendar, clock, or mileage meter. In cases where otherwise good oil is water- and/or solid-contaminated, filtration and/or water removal (oil reclamation) can restore the fluid, allowing continued use. Except when oil additives have been severely depleted, it is usually economically feasible to restore large volumes of oil. It should be noted that oil reclamation and polishing can extend equipment life, but is not a remedy for abnormal wear due to mechanical problems such as misalignment and fatigue. While changing or reclaiming the oil can alleviate those problems temporarily, further maintenance is necessary.

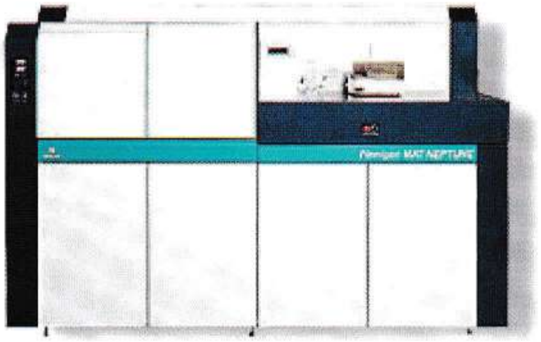
A rubber manufacturing plant in Ohio recently used 20 barrels of oil during the annual maintenance shutdown, compared to 60 barrels the previous year. This was accomplished by having all their major oil systems analyzed prior to shutdown. The effort sparked interest to extend lubricant life through reclamation, specifically by performing fine filtration and water removal. Periodic oil analysis at that plant is now standard. In computing the dollar savings, the cost of used oil disposal was a large factor.

5 Machine Wear Analysis

The wearing parts of a machine, such as the gears, hydraulic pistons, bearings, and wear rings, **do** generate fine metal particles during normal operation. At the onset of a severe wear mode, an increase in particle size as well as a change in the physical appearance can be observed. A knowledgeable analyst can relate this information to the mode of wear (with particle analysis and ferrography). Determining the wear status is accomplished by measuring the fine and course metal particles and examining them under a microscope. The testing for wear metals in a lab is divided into two categories:

- Screening tests
- Analytical/Diagnostic tests

ICP Spectrometer



Screening Tests

Measuring fine metal particles in an oil sample is usually accomplished by using an Atomic Emission (AE) Spectrometer. A small sample is introduced into a very hot arc, flame, or plasma, causing it to vaporize. Some of the metals in the sample, specifically the dissolved metals and the finest debris, absorb sufficient heat to also vaporize and enter a higher (excited) atomic state. When the excited metal atom cools at the edges of the flame, it emits a light burst (atomic emission) as it returns to its former, stable state. Each metal element has its own signature emission, and the spectrometer designer chooses the appropriate wavelength of light for the particular metal that is being analyzed. The light emission (in a rotrode spectrometer, this looks like a welder's electric arc) is transferred by fiber optic cable into the spectrometer section. Here, the light passes through a prism, is defracted, and projected onto a curved wall providing a "wide screen" display with short wavelengths at one end and long wavelengths at the other.

SOFTWARE FOR MANAGING OIL ANALYSIS DATA

Bently LUBE™ software is designed to help condition monitoring professionals manage and archive the data supplied by their oil analysis lab(s), providing powerful trending, alarming, and reporting capabilities. If you are not familiar with Bently LUBE software, we invite you to learn more by consulting the articles in our First and Fourth Quarter 2001 issues of ORBIT.

Today, Bently LUBE supports import from a specifically configured Microsoft® Excel spreadsheet, as well as standard interfaces for the following commercial labs:

- National Tribology Services (www.natrib.com)
- Intertek Caleb Brett (www.intertek-cb.com)
- MRT Laboratories (www.mrtlaboratories.com)
- Southwest Spectro Chem Laboratory (www.swsclabs.com)
- Caterpillar-certified labs (TAM II data format) (www.cat.com)
- Castrol Labs, U.K. (www.castrol.com)
- Mator Labs (www.mator.com)

If the lab you use is not in this list, simply contact us. We will work with you to engineer a solution that's right for your needs, using your preferred lab or labs. For more information on Bently LUBE software, and to request a demo CD, contact your nearest sales engineer, use the reader service card in this issue of ORBIT, or send an inquiry to orbit@ge.com.

5 continued

For example, if a wavelength of 259.940 nanometers is chosen for iron, a small aperture is placed in the screen at that point and a photo multiplier is placed there to collect the light of that specific wavelength. A wavelength is chosen for each particular metal of interest and is distinct from that emitted by the remaining metals. The output from each photo multiplier is fed to a computer that calculates the quantity of each metal present in the sample, reported in parts per million (ppm). Keep in mind that one percent (1%) is 10,000 ppm.

As important as the spectrometer is to oil analysis, it does have one severe limitation: in its normal operation, it only "sees" dissolved metals and the finest debris, which are generally associated with benign or normal wear. Coarse particles are of greater interest because they usually are generated by severe wear modes.

ROTRODE FILTER SPECTROSCOPY (RFS)

The AE spectrometer used in this method suffers from the same coarse particle limitation described above. However, that weakness is overcome by prefiltering the sample through one of the electrodes, called a rotrode. The rotrode is a porous carbon disc, and that characteristic makes it an ideal filter. A fixture has been designed (for use outside of the spectrometer) to clamp the disc so that the oil sample can be drawn through the outer circumference of the disc when a vacuum is applied to the inside (hub). The particles in the oil are captured by the surface of the rotrode, forming a thin line around the outside edge of the disc. Residual oil is washed away with solvent, the disc is allowed to dry, and the particles remain adhered to the rim of the rotrode in the right position to be vaporized when the rotrode is "zapped" in the spectrometer. The sensitivity of the method is excellent. A multi-station filtering fixture is used so that a number of samples can be filtered at once. The procedure is fast and economical, making it an ideal screening test for both analytical ferrography and/or patch tests.

Analytical/Diagnostic Tests: Analytical Ferrography & Patch Test

Both of these tests are methods of separating particles from the oil sample and laying them out in a configuration that can be explored under a microscope. Ferrography employs a magnetic separation technique that causes primarily ferrous particles to be deposited in a monolayer on a glass substrate, generally segregated by size and into strings of particles. The resulting ferrogram provides a permanent record of the ferrous wear in the machine.

A patch test is used when Rotrode Filter Spectroscopy (RFS) shows that primarily non-ferrous metals are involved with a severe wear mode, i.e., the presence of high levels of coarse, non-ferrous metals. Both tests allow the particles of interest to be explored under a high-powered microscope in order to identify the size, shape, metallurgy, and surface texture of the particles. This allows assessment of the wear condition in the machine and the source of the severe wear particles. These tests should only be performed on an exception basis because they are time consuming and expensive. Fortunately, technology is available today that combines traditional spectroscopy with RFS to quickly determine all the metals in the sample, both fine and coarse, making the decision whether or not to perform ferrography or a patch test easy.

RDE Spectrometer used in RFS

Integrated Condition Monitoring for a Polish Power Plant

How System 1® Software is Benefiting Elektrownia Turów S.A.

Leszek Kaniewski
Rotating Machinery Diagnostic Specialist
Elektrownia Turów S.A.
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About Turów

Elektrownia Turów S.A. is located in Poland's Zytawska Valley, where the country forms a 3-way intersection with the borders of Germany and the Czech Republic. The power plant has been in continuous operation since 1962 and, together with a neighboring lignite coal mine providing fuel for the plant, comprises the economic foundation of the local region.

The plant is a leader in the Polish power industry and has emerged as a showcase for proactive plant asset management in Eastern Europe. With a power output of 2.0 GW provided by nine turbine-generator sets, the Turów plant is also home to the world's largest fluidized-bed boiler.

About the Project

Initially, the search for the right company to help structure and implement our plant asset management methodology focused on an online system for the plant's most critical machines: three new turbine-generator sets. That was in 1999, and the System 1® platform was still not commercially available. However, the estimated release date of the product for early 2000 coincided reasonably well with our timetable.

At Turów, we divide our machinery into two broad categories: "critical" (such as the turbine-generators) and "helping" (such as numerous pumps, motors, mills, blowers, and compressors). Critical machinery is monitored via a continuous online system, while helping machinery is monitored via a portable data collection instrument.

As Y2K approached, we were forced to re-evaluate our initial plans of focusing only on online software for the critical machinery. We discovered that our existing walk-around instruments and software were not Y2K-compliant. Thus, the search broadened to a company and a product able to encompass both our walk-around data collection for helping machinery and online data collection for critical machinery. Functionality that would allow us to manage all of our machinery in a single, integrated platform was very appealing.

Past Experience Helped Selection Decision

To help in the overall purchasing decision, we were able to draw on our experience with the Bently Nevada® products we were already using – a portable ADRE® for Windows® system purchased in 1995, and a Data Manager® 2000 (DM2000) online system. The Bently Nevada website provided a Y2K compliance statement well in advance, and the local sales and support team communicated proactively to let us know the status of the products we owned (neither ADRE nor DM2000 hardware/firmware/software were affected). This level of support and communication impressed us.

Another factor that influenced our decision was the way that our ADRE and DM2000 software had been continually enhanced with regular updates and upgrades. This provided us with the confidence that System 1 software would not be a "static" product, but would continue to improve via regular updates. The technical support team and

A machinery specialist at Turów conducts a predictive maintenance route using a Snapshot™ for Windows® CE data collection instrument.

local service personnel led us through some major upgrades and updates, as computers became faster and operating systems became more powerful, without the pain normally associated with software upgrades.

Finally, we were impressed with the way GE Energy personnel continually focused on the value of Bently Nevada products when engaging with us – something we had experience with. For example, our ADRE System had provided very quick payback when, following an overhaul of a turbine-generator set, ADRE data indicated an oil instability. Since the case-mounted transducers showed normal vibrations, it was solely due to the ADRE System and our Bently Nevada proximity probes that this malfunction was spotted and diagnosed. Without intervention, the bearing would have been very quickly destroyed.

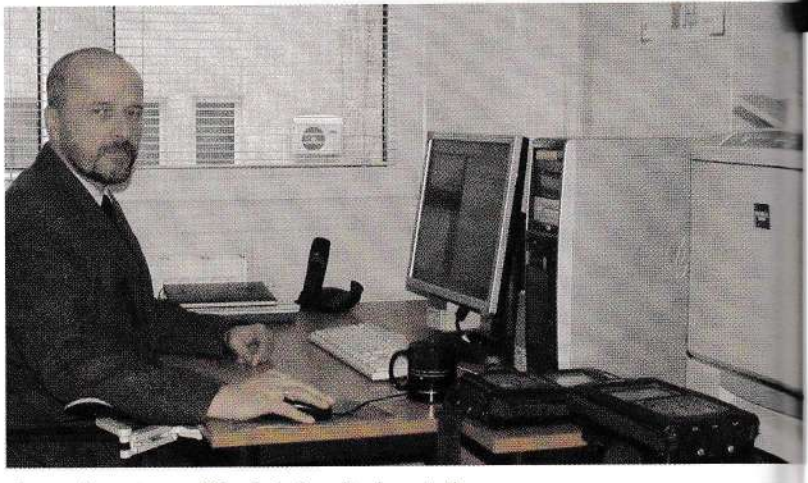
Subsequently, we chose System 1 with the confidence that this level of service and support would be there for the new platform, along with the promise of advanced functionality and integration. Focusing initially on replacement of our non-Y2K-compliant data collection system, we became one of the first customers to purchase System 1 along with the Bently Nevada Snapshot for Windows CE data collector.

An Evolving System

In the five years since initial installation, the system has matured significantly. We found the Bently Nevada team to be very responsive to our wants and needs, and as the software has been enhanced over the years, it has become even more of what we want in a condition monitoring system.

One of the most significant milestones in our plant asset management "journey" was when we added the critical machinery from Blocks 1, 2, and 3 to our System 1 installation. As we have increased the number of assets encompassed by System 1 software in our plant, more and more plant specialists have become interested in and familiar with the system (turbine generator operators, pneumatic station compressor operators, boiler operators, etc.). Also, the different plant division managers have quickly learned that the data/information present within System 1 software can be used by them directly for a wider variety of applications to optimize the Turów facility – not just machinery diagnostics. Currently, we have ten display computers around the plant, supporting multiple specialists who use System 1 software for various asset management applications.

FROM EXPERIENCE, WE UNDERSTOOD THE VALUE OF BENTLY NEVADA PRODUCTS.



The author at one of Turów's ten display stations for their enterprise-wide System 1® installation.

Multiple Users, Multiple Wins

Department managers like the system because it gives them 24/7 historical and real-time data, helping establish actual machinery condition. The plant division managers currently using the system have responsibility for the circulating pumps, feed water pumps, boiler, fans, exhaust blowers, motors, and generators.

Diagnosticians, such as myself, like the system because it gives us all the tools necessary to do what we do best: diagnose the machinery. The following are recent examples of how System 1 software has helped us identify and correct problems:

The exhaust blower where a clogged grease line was starving the bearing of necessary lubrication.

- **Lubrication problems with an exhaust blower.** High axial vibration, thought to be due to under-greasing, was first addressed by adding grease. Surprisingly, System 1 software continued to show high vibration. Further investigation uncovered the root cause: the grease line was clogged. The problem was fixed and vibration returned to expected levels.
- **High vibration on a feed water pump clutch.** Disassembly of the clutch allowed us to find and correct root cause, preventing further degradation and recurring clutch problems.
- **Imbalance on an exhaust blower.** Balancing reduced the vibration five-fold.
- **Bearing degradation on a water pump motor.** Failure to spot this problem would have led to an unplanned shutdown.
- **Oil problems on a compressor.** Oil replacement returned the machine to normal operation.
- **Bearing problems in both condensate and water pumps.** A replacement of the bearings was scheduled during planned outages, avoiding in-service failures and collateral machinery damage.

System Capacity

Currently, our System 1 installation is configured for two "enterprises" with one dedicated to online "critical" machines, and the other to offline data collected from "helping" machines. We have 283 real-time online points, and 3600 offline points currently coming into the system, and if we eventually exceed the 4000 points in our license agreement, we will simply add more using the software's modular expansion capabilities.

The Right Decision

Looking back, we are confident that we made the right decision in choosing System 1. Although we were one of the first customers of a brand new system, it is providing the value we expected, it has evolved with our needs, and we have received the level of outstanding service and support that we have come to expect from our investment in GE Energy's Bently Nevada® Condition Monitoring Solutions.

The All-New ADRE® System

Completely redesigned, fifth-generation system is better than ever

the Orbit

Premier Edition

published by Bently Nevada Corporation summer 1980

BENTLY NEVADA INTRODUCES ADRE

WELCOME TO THE ORBIT

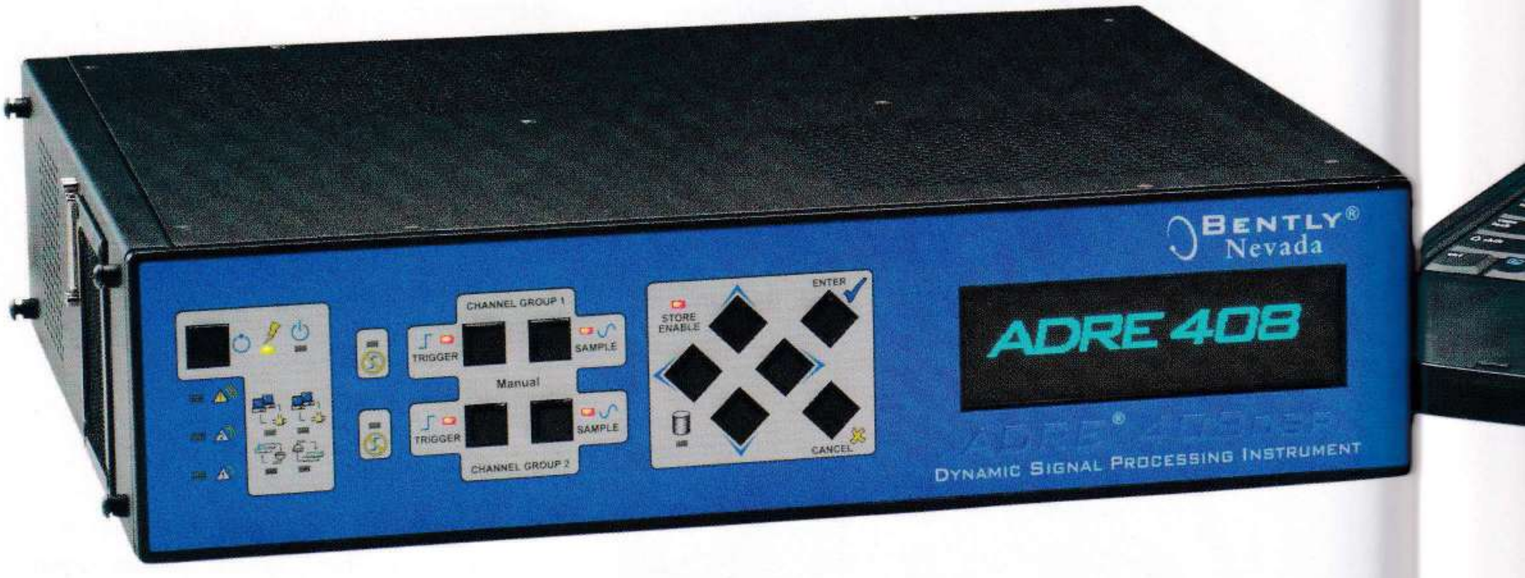
NEW LOW SPEED VIBRATION MONITOR

Dateline: 1980

In the summer of 1980, two important introductions occurred for our customers. The very first issue of ORBIT was published and ADRE was first introduced. In fact, that premier issue of ORBIT prominently announced on its front cover, "Bently Nevada Introduces ADRE."

Here's an excerpt:

Bently Nevada begins the new decade with the introduction of ADRE ... the answer to the tedious, time-consuming chore of acquiring and reducing data collected on the operating parameters of rotating equipment.



1980 – ADRE I/II

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1986 – ADRE 3

1993 – ADRE for Windows®

> THE PRODUCT'S STRENGTH HAS STEMMED FROM THE TREMENDOUS AMOUNT OF USER FEEDBACK INCORPORATED IN SUCCEEDING GENERATIONS OF ADRE.

That was 25 years ago, and the ADRE System has come a long way from its beginnings as a rather bulky suite of equipment comprising analog tape recorder, digital vector filter, multi-channel amplifier, spectrum analyzer, external floppy disk drive, real-time clock, printer, and an early HP desktop computer (well before Microsoft® and the PC revolution had become industry standards). While portable in theory, perhaps a better description for this system was "luggable" since it weighed several hundred pounds and required numerous large cases. That probably explains why most of our own machinery diagnostics engineers drove pick-up trucks in those days. It also explains why they preferred to gather data on tape and return to their office to "post process" the data in their ADRE System rather than transport all the gear to site.

Today's ADRE System is smaller, faster, and vastly more capable than that early system. Through five succeeding generations of hardware and software enhancements, it has steadily improved – and while it has always been our desire to provide the functionality of all the above instruments in a single package, that remained an elusive goal. Today, however, technology has enabled us to deliver a product that is truly self-contained, redefining "portability." Finally, you can leave that tape recorder, scope, spectrum analyzer, and signal conditioning apparatus behind.

YOU TOLD US YOU NEEDED...

- more channels of data collection
- "stand-alone" operation
- combined multi-function capability in a single system
- real-time data presentation
- extended frequency ranges
- flexible signal inputs
- multiple sampling rates
- large data storage capacity
- quick configuration
- fast remote/network operation
- graphical correlation tools
- high-resolution, high-capacity tape-less recording
- true unattended data logger capabilities
- total remote access, control, and configuration via WAN and LAN
- true client/server functionality with simultaneous multiple client access

...THE ALL-NEW ADRE SYSTEM DELIVERS THESE AND MUCH MORE

It's All About The User...

The legacy of the ADRE System spans decades, with thousands of users around the world. In fact, many of the machinery diagnostic case histories we've featured in ORBIT over the last 25 years have used the ADRE System as the underlying tool to capture and analyze the data. The product's strength has stemmed from the tremendous amount of user feedback incorporated in succeeding generations of the ADRE System. Whether machinery OEMs using the product on their test stands, field engineers gathering data, or our own machinery diagnostics personnel troubleshooting machinery at customer locations globally, the ADRE System has always been about users telling us what they need, and then our engineers designing and enhancing the system around this feedback. This latest generation is no exception.

BECAUSE THE 408 DSPI IS A TRUE SERVER, ANYONE WITH PROPER ACCESS PERMISSIONS, ANYWHERE IN THE WORLD CAN VIEW, CONFIGURE, AND CONTROL THE INSTRUMENT.

Over two years ago, the GE Energy team began to work on creating a new ADRE System based on the feedback they had been receiving from both internal and external users. These users provided what seemed to be an endless list of needs and desires. However, a common theme was clear: better usability and better performance.

To address these needs, and much more, we're pleased to introduce ADRE Sxp software and 408 DSPi (Dynamic Signal Processing Instrument) hardware. Below, we summarize a few of the important new capabilities contained in this latest generation of the ADRE System:

- **LAN/WAN Connectivity and Client/Server Architecture**

  The new ADRE System's unique client/server architecture and LAN/WAN connectivity frees users from the logistical constraints that traditional data collection units were tied to. Now, multiple users can view and control data from anywhere in the world through local or wide area networks (LANs or WANs), all in real-time. We have specially engineered the 408 DSPi's Ethernet communications to be compatible with corporate IT structures and firewalls, allowing it to securely reside on your network while making its data available to everyone that needs it. The potential for time and travel cost savings are enormous. Because the 408 DSPi is a true server, anyone with proper access permissions, anywhere in the world can view, configure, and control the instrument. It even supports multiple simultaneous clients – each viewing completely different data. The ADRE System truly was created with all users in mind, enabling many powerful usage scenarios:

  - A 408 DSPi could be located on a test stand in the United States where a machine was being readied for a customer in China. The customer in China could view data in metric units while the test stand engineer viewed the same data in English units. Or, the customer might be viewing real time slow-roll data to see if runout was within acceptable limits while the test stand engineer examined an archived bode plot to verify the machine's amplification factor.
  - A 408 DSPi could be deployed at an unstaffed facility, connected to the company's LAN or WAN, and data from the machine(s) could be collected for days, weeks, or months. The ADRE System can be fully configured and controlled remotely, as well as providing complete remote access to all archived and real time data.
  - A 408 DSPi could be connected to a machine and process control system while a plant was undergoing a routine outage as part of a service for a Bently Nevada® machinery diagnostics engineer to provide start-up data collection and analysis assistance. The engineer could return to the office and remotely access all data when the start-up commenced, avoiding stand-by charges at site. When finished collecting data, site personnel could disconnect the instrument and ship it back. If necessary, the machinery diagnostics engineer

An integrated user interface and 130+ GB storage capacity allows the 408 DSPi to be used in stand-alone mode for days, weeks, or months.

could collaborate in real time with the machinery OEM, other colleagues, and the customer – all accessing the same system using their individual copies of ADRE Sxp software.

— A 408 DSPi could be connected to a machine located in a remote part of the plant and connected to the plant's LAN. The engineer could return to the comfort of his own office, launch ADRE Sxp software from his desktop, and fully access and control the ADRE 408 DSPi hardware.

- **Stand-Alone Operation**

The places you gather data don't always represent the most hospitable environments for using a laptop computer. Heat, cold, humidity, dust, bright sunlight, noise – they can all make it tough when your data collection instrument can't be easily separated from its display software. We've taken special care to provide a user interface on the ADRE 408 DSPi hardware that allows it to be used independent of a computer connection for the majority of your configuration and data collection needs. Rugged buttons and icons, a bright fluorescent display, status LEDs, and intuitive menus make the instrument easy to use in stand-alone mode. Its LAN/WAN connectivity and client/server architecture, as discussed above, mean you can leave the instrument unattended for days or weeks at a time while connecting when needed to reconfigure, manually trigger special data capture, view real time or archived data, and collaborate with colleagues.

- **New Data Types for More Industries**

The ADRE System's strength has always been its purpose-built focus on data acquisition for rotating and reciprocating machinery. We've retained all of that in this newest version, but we've also expanded the hardware and software capabilities so that it can be used for general purpose data acquisition of nearly any parameter encountered in the field or test stand. If the signal is available as a proportional voltage or current – static or dynamic – the ADRE System now has the ability to gather it and the software tools to display and interpret it.

- **Scalability**

The new ADRE System is completely scalable. 8-channel dynamic sampling cards, 3-channel phase reference (Keyphasor®/speed) cards, discrete input cards, and a special accessory slot (for future enhancements) allow you to configure your hardware with only the channel capacities and types that you require. A single ADRE 408 DSPi chassis is capable of collecting data from up to 32 dynamic channels. In the product's next release, you'll be able to interconnect up to four (4) 408 DSPi units in a master/slave configuration for up to 128 channels of dynamic/static data

The ADRE System's architecture is highly scalable, using modular I/O cards to match your requirements for input types and quantities. Up to 32 dynamic inputs can be used per chassis.

inputs, or up to 112 channels when 6 phase reference inputs are added.

- **Storage Capacity**

  The ADRE 408 DSPi comes with a standard internal data storage capacity of more than 130+ Gigabytes, allowing it to collect large amounts of high-resolution data for hours, days, or even weeks without ever needing to be connected to an external PC. In the event you need additional storage, the 408 DSPi has a convenient connection to standard external hard drive arrays for practically unlimited data capacity.

- **"Single Instrument" Functionality**

  As noted earlier, we've specifically approached the ADRE System's design with the objective of eliminating your need to pack multiple other instruments such as oscilloscopes, spectrum analyzers, tape recorders, signal amplifiers, and speed/phase signal conditioners. The 408 DSPi combines the functionality of all these instruments into a single, compact, portable package – without sacrificing power, speed, or functionality.

- **Expanded Frequency Span**

  The new 408 DSPi has a frequency span of 50 kHz across all channels simultaneously. In contrast, some platforms make frequency span a function of channel count, forcing the user to choose between data quality and data quantity.

- **Real Time Data Streaming and Processing**

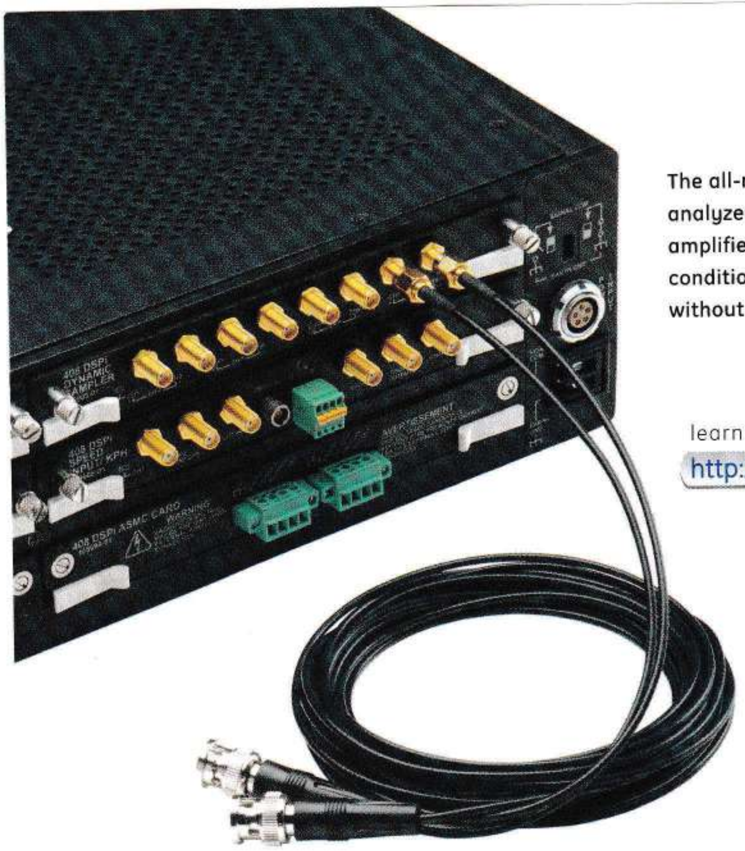
  The 408 DSPi can handle enormous real time data throughput. The design philosophy underlying the new ADRE System was to provide real time processing, rather than extensive reliance upon post processing to provide the data of interest to the user. In other words, the system provides not just "raw" data streaming in real time, but processed data as well. You can view all of the information as it happens, whether the parameters of interest are highly processed (such as RMS amplitudes from a tracking filter) or not (such as overall unfiltered vibration amplitude). However, this real-time capability does not preclude you from using the ADRE System to further post-process data. You always retain the option of further manipulating and processing data in any way you want.

- **Rack Mounting**

  Test stand and R&D applications often require instruments that can be mounted in conventional 19" EIA racks. To address these needs, the ADRE 408 DSPi can be ordered with a convenient and rugged rack-mounting kit for permanent or semi-permanent installations.

- **Backward Compatibility**

  Data you have already collected and archived with previous generations of ADRE Systems are compatible with our latest system. Your ADRE for Windows databases



The all-new ADRE System replaces spectrum analyzer, oscilloscope, tape recorder, signal amplifiers, and external speed/phase input conditioners in a single, compact instrument without sacrificing any functionality.

learn more online at

http://www.gepower.com/o&c/ADRE

are easily migrated into the new ADRE Sxp software platform, providing complete continuity and current/historical data access from a single environment.

- **Balancing Software Compatibility**

  A very common use for the ADRE System is complex, multi-plane balancing of turbomachinery under various load and speed conditions. Bently BALANCE® software is designed specifically for addressing these complex tasks, and is fully compatible with ADRE Sxp software. You can seamlessly transfer data collected with your ADRE System to our balancing software, without the need for tedious manual typing and data entry.

Great Software – The Key To Usability

In a recent interview, a renowned CEO from one of the most innovative and successful technology companies in the world stated that the key to their success was in creating great software products that make the interface between the user and their hardware intuitive, friendly, and extremely usable. We feel the same way. Usability and ease of operation is what makes the new ADRE Sxp software the perfect complement to the power of the 408 DSPi hardware. Imagine being able to go from "out of the box" to data collection in minutes. With the new ADRE System's amazingly easy-to-use Sxp software, it has never been easier or faster to install, configure, and start collecting data – and, we've accomplished this without sacrificing functionality. ADRE software is more powerful than ever with the most extensive array of plot types, reporting capabilities, import/export abilities, and analysis tools that we have ever offered in this platform. The result is a system that delivers both usability and capability, without compromising either one.

The Wait Is Over

Prior to release, we have been discussing this all-new ADRE System with customers at tradeshows, meetings, and user groups – as well as our own services personnel. From all of them, the feedback has been the same: "when can I get one?"

As of July 2005, the wait is over. We're so proud of this product that we know one demonstration is all you'll need to understand what all the excitement is about – and to want your own ADRE System. Learn more in our informative 12-page brochure by accessing it on our website, by using the Reader Service Card attached to this issue of ORBIT, or by contacting your local sales professional who can provide you with literature, arrange a demonstration, and answer your questions.

ADRE Specifications

Physical	
Weight @ 32 channels	7.5 kg (16.5 lbs) per 408 DSPi Unit (32 channels w/power supply)
Environmental	0° C – 50° C; 0 to 95% relative humidity (non-condensing)
Mounting	Benchtop or optional 19" EIA rack mounting kit
Channel Status LEDs	Per channel: Over-range, NOT OK
Power Requirements	110 – 240V 50-60 hz
Inputs	
Number of Dynamic Channels	8/16/24/32 per chassis – expandable to 128 (4 chassis linked together[†])
Throughput Rate	Up to 50 MB/sec per channel
Transducer Inputs	Proximity/Velocity/Acceleration/Phase Reference/Speed
Differential Inputs	Selectable: True differential or single-ended
Process Inputs	Programmable: 4-20 mA; 0-10 vdc; -12 to +12 vdc; -25 to +25 vdc
Voltage Input Range	Programmable lower and upper values from -25 vdc to +25 vdc
Gain Selections	Auto Gain between -25 vdc and +25 vdc
Input Impedance	> 700 kΩ
Signal to Noise Ratio (Dynamic Range)	110dB
Frequency Span (All Channels)	Up to 50 kHz – All Channels Simultaneously
Speed Range	1 – 120K RPM
Speed/Trigger Input Sources	Proximity probes, optical sensors, magnetic pickups
Speed Input Capacity	3/6 physical, 6 simulated (internal)
Trigger Sources	Multiple "OR" voting of Speed/Time/Amplitude/External Contacts
Keyphasor® multiplier/divider/conditioner/power	Integrated (per speed input)
AC/DC coupling	Yes; Configurable per channel
Channel Bandwidth	Up to 50 kHz (simultaneous, all channels)
Software	
Required Software	ADRE Sxp, real time and post-processing
View Data From Multiple Runs Simultaneously	Yes – Unlimited
Keyphasor Dynamic Display	Per Keyphasor
Instrument Mode Display Update	100 ms/sample (max)
Communications	Integrated 10/100/1000 Mb Ethernet TCP/IP
LAN/WAN support	Yes; specially designed for firewall management
Remote Operation via LAN/WAN	Yes
Security	Administrative/Read Only/No Access
Signal Conditioning	
A to D Resolution	24 bit
Filtering	High-/Low-Pass: selectable; Bandpass: 2-, 4-, 6-, 8-pole selectable
Tracking Filters	Realtime; up to 6 nX per channel
Tracking Filter Bandwidth	Configurable: 1.2/12/120 CPM; constant bandwidth auto-switching
Auto Switching Tracking Filters	Selectable
Sub-Synchronous nX Tracking	Configurable: 0.1 to nX (in .01X increments)
nX Vectors	Configurable – up to four different vectors
Sampling	• Simultaneous Processed and Raw Data (All Channels) • Multiple Simultaneous Sampling Rates (Synch and Asynch) • Delta Sampling for RPM, Time, or Amplitude[††] • Synchronous Sampling configurable for 2 Rates Per Channel • Continuous and Discrete (configurable) • Realtime simultaneous synchronous and asynchronous
Synchronous Sampling Rates	16/32/64/128/256/360/512/720/1024 samples per revolution
Anti-Aliasing	FIR Filter (passband @ 50 kHz, – 100 dB @ 64 kHz)
Waveforms	4 per channel simultaneously (user-configurable) + RAW
Spectral Resolution	Configurable – up to 6400 lines (all channels simultaneously)
True Zoom Capabilities	Yes
Recording	
Data Storage Capacity	Internal: 130+ GB; External: unlimited via external drive arrays
Pre- and Post-Event Data Capture	Yes; configuration dependant
Vector-to-Waveform Storage Ratio	n:1 configurable
Continuous Digital Recording	Yes; internal
Outputs	
Speed/Trigger Outputs	3/6 Digital and Analog Conditioned

[†] Multi-chassis interconnection not available until after first release. All required hardware is currently in place.

[††] Delta amplitude sampling not available at initial release.